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Jadestone Energy PLC
29 April 2024

2023 Full Year Results

29 April 2024-Singapore: Jadestone Energy plc (AIM:JSE) ("Jadestone" or the "Company"), an independent upstream company and its subsidiaries (the "Group"), focused on the Asia-Pacific region, reports its consolidated financial statements (the "Financial Statements"), as at and for the financial year ended 31 December 2023.

The Company will host a webcast at 9:00 a.m. UK time today, details of which can be found in the announcement below.

Key updates:

- Proven and Probable ("2P") reserves at 31 December 2023 of 68.0 mmboe (31 December 2022: 64.8 mmboe), representing 164% 2P reserves replacement during the year. 2C contingent resources increased slightly to 105.6 mmboe (31 December 2022: 104.3 mmboe).
- Commercial gas sales from the Akatara gas field expected to commence before the end of the second quarter of 2024, consistent with previous guidance.
- March 2024 reserve-based lending ("RBL") facility redetermination has set a borrowing base of US$200.0 million for the six- month period ending 30 September 2024.
- The 2024 production guidance range is narrowed from 20-23,000 boe/d to 20-22,000 boe/d. The change to the upper end of guidance reflects first quarter Group production performance, which was impacted by both planned and unplanned downtime across the portfolio. Current internal forecasts point to an outcome at the lower end of the updated guidance range, based on first commercial gas sales from Akatara in June 2024, albeit there remains a wide range of possible outcomes, principally based on the timing and nature of Akatara's ramp up, as well as initiatives underway to optimise production at the Group's current producing assets.
- 2024 operating cost guidance is unchanged at US$240.0-290.0 million (excluding forecast royalties and carbon taxes totalling c.US$30.0 million).
- 2024 capital expenditure guidance is unchanged at US$80.0 - 110.0 million.
- US$91.3 million loss after tax for 2023 (2022: US$9.2 million profit), principally driven by lower oil prices year-on-year, downtime at Montara for FPSO tank repairs, asset impairments and higher finance costs.
- Net debt of US$78.2 million at 31 March 2024 (31 December 2023: US$3.6 million) reflects c.US$121.8 million of consolidated Group cash balances and US$200.0 million of debt drawn under the Group's RBL facility. The end March 2024 net debt figure excludes an estimated US$110.5 million of proceeds for March 2024 liftings which were received in April 2024.

Paul Blakeley, President and CEO commented:

"2023 was a pivotal year for Jadestone, as we continued the deliberate move away from our older legacy assets in Australia towards newer and higher-value, higher-margin assets across the Asia-Pacific region. During the year we achieved a number of operational and strategic milestones, including significant progress toward first gas at Akatara, a very successful infill drilling campaign offshore Malaysia and 164% replacement of 2P reserves. Closing the Sinphuhorm acquisition and doubling our interest in the CWLH fields offshore Australia were also key steps in the ongoing diversification strategy. Commercial progress on Nam Du/U Minh in early 2024 provides greater confidence in our medium-term outlook. We also delivered a strong HSE performance during the year, with no lost time injuries, and bolstered our pledge to deliver Net Zero Scope 1 and 2 GHGs from our operated assets by 2040 through establishing interim GHG reduction milestones.

While these positive developments were somewhat overshadowed by a disappointing performance at Montara in the first half of 2023, we have since seen steady progress in the asset's reliability as the ongoing work to the FPSO has helped support improving uptime.

Partly as a result of the challenges at Montara and lower realised oil prices the business made a loss of US$91 million in 2023 (2022: US$9 million profit). With stronger oil prices so far this year and our production growing, we expect 2024 to deliver a much better outcome, with the recent March 2024 RBL redetermination setting a borrowing base of US$200 million for the next two quarters, more than double the predicted lending capacity for this period only a year ago and underpinning near-term liquidity. Akatara cashflows and the recent increase in our CWLH stake will further diversify and increase the robustness of our cash generation.

In recent months, the construction activity at the Akatara gas processing facility ("AGPF") has been coming to a conclusion in preparation for first gas. The sales gas pipeline has been completed and successfully tested, with four out of the five planned production wells successfully worked over and the first three tested at a combined rate in excess of 30 mmcfd, well above the 25 mmcfd required to meet deliveries under the gas sales agreement. We currently anticipate that commissioning gas will be introduced into the AGPF followed by commercial gas sales before the end of the second quarter, consistent with our long-standing guidance. There is still significant activity to complete, but we are on the threshold of a significant milestone for Jadestone.

Average production for the Group in the first quarter of 2024 was 17,200 boe/d, which primarily reflects the impact on our Australian assets of a very active cyclone season at the start of this year. Accordingly, production guidance for 2024 has been narrowed to 20-22,000 boe/d. Both the 2024 opex and capex guidance ranges are reiterated today.

While the sale process for Woodside's interests in the Pyrenees/Macedon fields did not proceed, bringing the related share trading suspension to an end, we had provided a competitive and fully funded proposal without any recourse to equity. The learnings from this process provide us with the financial framework to continue assessing the exciting set of inorganic *opportunities across the Asia-Pacific region, through which we are well placed to create value from our operating platform and capability. Finally, I would like to take this opportunity to thank my colleagues at Jadestone for their hard work in 2023, and our shareholders for their patience and continued support."*

Paul Blakeley

EXECUTIVE DIRECTOR, PRESIDENT AND CHIEF EXECUTIVE OFFICER

2023 SUMMARY

USD'000 except where indicated	2023	2022 Restated*
Sales volume, barrels of oil equivalent (boe)	3,862,741	4,326,770
Production, boe/day[1]	13,813	11,487
Realised oil price per barrel of oil equivalent (US$/boe)[2]	87.34	103.85
Realised gas price per thousand standard cubic feet (US$/mscf)	1.53	1.63
Revenue[3]	309,200	421,602
Production costs	(232,772)	(250,300)
Adjusted unit operating costs per barrel of oil equivalent (US$/boe)[4]	37.24	37.49
Adjusted EBITDAX[4]	90,647	162,329
(Loss)/Profit after tax	(91,274)	9,237
(Loss)/Earnings per ordinary share: basic & diluted (US$)	(0.18)	0.02
Operating cash flows before movement in working capital	36,499	158,548
Capital expenditure	115,882	82,876
Net (debt)/cash[4]	(3,596)	123,329

Operational and financial summary

- 2P reserves at year-end 2023 totalled 68.0 mmboe, a 5% increase on year-end 2022 (64.8 mmboe), mainly due to the acquisition of the Sinphuhorm Assets and increases at the CWLH Assets, PenMal Assets and Lemang PSC, partly offset by a reduction at Montara, and representing a 2P reserves replacement of 164%;
- 2023 production increased by 20% year-on-year to an annual record of 13,813 boe/d (2022: 11,487 boe/d), primarily attributable to a full-year of production from the CWLH Assets in 2023 compared to two months in 2022, and the contribution of the Sinphuhorm Assets from closing of the acquisition in February 2023. This increase was partly offset by lower production at Montara due to the impact of FPSO tank repairs;
- Total lifted volumes in 2023 reduced by 11% to 3.9 mmboe compared to 4.3 mmboe in 2022, mainly reflecting lower production at Montara;
- Total revenue decreased by 27% to US$309.2 million (2022: US$421.6 million) due to a 16% decrease year-on-year in realised prices, combined with lower lifted volumes. Total 2023 revenue includes a hedging loss of US$10.3 million from commodity swap contracts entered into in support of the reserves-based lending ("RBL") facility;
- The average realised oil price for the year before hedging was US$87.34/bbl in 2023 (2022: US$103.85/bbl). The average realised price premium was US$5.58/bbl for 2023 (2022: US$7.81/bbl);
- Production costs totalled US$232.8 million in 2023, a 7% decrease from US$250.3 million in 2022. This decrease was primarily driven by a credit for inventory changes and lower supplementary payments in Malaysia, which more than offset a full year of operating costs at the CWLH Assets and higher tanker cost and fuel charges at Stag and Montara;
  - 2023 adjusted unit operating costs[3] of US$37.24/boe were unchanged year-on-year (2022: US$37.49/boe);
- 2023 adjusted EBITDAX decreased by 44% to US$90.6 million, compared to US$162.3 million in 2022, primarily due to the revenue effects detailed above;
- 2023 net loss after tax of US$91.3 million (2022: US$9.2 million profit after tax);
- 2023 operating cash flow before movements in working capital of US$36.5 million, a decrease of 77% compared to 2022 (US$158.5 million);
- 2023 capital expenditure of US$115.9 million was 40% higher year-on-year (2022: US$82.9 million), primarily due to the ramp up of activities at the Akatara development project onshore Indonesia;
- Closed c.US$282.0 million of debt facilities and raised US$51.0 million equity capital during the year:
  - A US$50.0 million Interim Facility was closed in February 2023 and partly used for the acquisition of the Sinphuhorm Assets, with the Interim Facility fully repaid upon closing of the RBL facility;
  - A US$200.0 million RBL facility was closed in May 2023, supporting the Group's strategy and investment program;
  - A placing and open offer in June 2023 raised c.US$51.0 million, net of costs; and
  - A US$31.9 million standby working capital facility was closed in June 2023, providing additional liquidity in support of the Group's investment plans. The standby working capital facility expires on 31 December 2024.

- Net debt of US$3.6 million at 2023 year-end (2022 year-end: net cash of US$123.3 million), reflecting a drawdown of US$157.0 million from the RBL facility and total cash and cash equivalents of US$153.4 million. The US$31.9 million working capital facility remained undrawn following closing in June 2023.
  - The RBL facility debt capacity upon closing in May 2023 was US$200.0 million. The September 2023 redetermination confirmed a debt capacity of US$200.0 million for the 1 October 2023 to 31 March 2024 period, and reflected consent from the RBL banks to increase the contribution of the Akatara project to debt capacity in the development phase;
  - The scheduled RBL March 2024 redetermination concluded on 26 April 2024, resulting in a borrowing base of US$200.0 million. Stag has been removed from the borrowing base assets and replaced with the second acquisition of 16.67% of the CWLH assets, acquired on 14 February 2024. The effective date for the redetermination and the change to the borrowing base is 1 April 2024.

Significant and subsequent events

- On 19 January 2023, the Group executed a sale and purchase agreement to acquire a 9.52% non-operated interest in the producing Sinphuhorm gas field and a 27.2% interest in the Dong Mun gas discovery onshore northeast Thailand (the "Sinphuhorm Assets");
- On 22 May 2023, the Group announced the closing of a US$200.0 million RBL facility. In support of the RBL facility, the Group entered into a hedging program through executing oil price swap contracts for 5.5 mmbbls over the period Q4 2023 to Q3 2025 at an overall weighted average price of US$70.57/bbl;
- In June 2023, the Company raised US$51.0 million (net of costs) through an equity placing and open offer issuing 94,081,826 ordinary shares at a price of £0.45 per share. The offer was underwritten by Tyrus Capital Events S.a.r.l., the Company's largest shareholder. As part of the underwriting arrangement, Tyrus Capital S.A.M. and funds managed by it received warrants for 30 million ordinary shares with an exercise price of £0.50 per share and exercisable any time within 36 months from the date of issue;
- On 14 November 2023, the Group executed a sale and purchase agreement with Japan Australia LNG (MIMI) Pty Ltd, to acquire a non-operated 16.67% working interest in the Cossack, Wanaea, Lambert, and Hermes ("CWLH Assets") oil fields development, offshore Western Australia, for a total initial cash consideration of US$9 million, and certain subsequent Abandonment Trust Payments (the "Acquisition"). The Acquisition was completed on 14 February 2024, with a net receipt to the Group of US$6.3 million, reflecting the accumulated economic benefits of the CWLH assets for the period between the effective date of 1 July 2022 to completion. As a result, the Group's non-operated working interest in the CWLH assets increased to 33.33%, from 16.67%;
- On 26 January 2024, the Group signed a Heads of Agreement ("HoA") with PetroVietnam Gas Joint Stock Corporation ("PV Gas") for the Gas Sales and Purchase Agreement ("GSPA") relating to the Nam Du and U Minh gas fields development offshore Vietnam. The HoA forms the basis for negotiations over a fully termed GSPA, which supports the submission of an updated Field Development Plan ("FDP") for the Nam Du and U Minh fields, the approval of which is key for progressing to a Final Investment Decision for this project; and
- On 13 February 2024, the ordinary shares of the Company were suspended from trading pursuant to a proposed sale by Woodside Energy Group Ltd. ("Woodside") of its participating interests in the Macedon and Greater Pyrenees Projects offshore Western Australia (the "Proposed Acquisition"). Had Jadestone been selected as the preferred bidder and reached agreement with Woodside on acquisition terms, the Proposed Acquisition would have been classified as a reverse takeover transaction in accordance with AIM Rule 14, and accordingly, the Company's ordinary shares were suspended from trading on AIM on 13 February 2024. On 11 April 2024, Woodside cancelled the sale of its participating interests in those assets. With the possibility of the Proposed Acquisition ceasing, the Company's shares resumed trading on AIM on 11 April 2024.

2024 Guidance

- The 2024 production guidance range is narrowed from 20-23,000 boe/d to 20-22,000 boe/d. The change to the upper end of guidance reflects average first quarter Group production performance of c.17,200 boe/d, which was impacted by both planned and unplanned downtime across the portfolio, particularly at the offshore Australia assets relating to the recent cyclone season. Current internal forecasts point to an outcome at the lower end of the updated guidance range, based on first commercial gas sales from Akatara in June 2024, albeit there remains a wide range of possible outcomes, principally based on the timing and nature of Akatara's ramp up, as well as initiatives underway to optimise production at the Group's current producing assets. 2024 production guidance will be kept under review, particularly in relation to the first gas schedule at Akatara, and further updates will be provided when appropriate;

- 2024 Group operating cost guidance is unchanged, and is expected to total US$240.0-290.0 million (excluding forecast royalties and carbon taxes totalling c.US$30.0 million); and
- 2024 Group capital expenditure guidance is unchanged, and is expected to total US$80.0-110.0 million, with other cash expenditure still expected to total c.US$77.0 million on a net basis, primarily reflecting the previously announced CWLH 2 acquisition abandonment funding payments.

*Restatements explained in Note 50 of the Group's consolidated financial statements.

[1] 2023 Production includes the Sinphuhorm Assets gas production in accordance with Petroleum Resource Management Systems guidelines, however in accordance with IAS 28 the investment is accounted for as an associated undertaking and only recognises dividends received. Accordingly, the revenue and production costs from the Sinphuhorm Assets are excluded from the Group's financial results.

[2] Realised oil price represents the actual selling price inclusive of premiums.

[3] Revenue in 2023 of US$309.2 million consist of a hedging loss of US$10.3 million from the commodity swap contracts entered into in support of the RBL facility.

[4] Adjusted unit operating costs per boe, adjusted EBITDAX and net debt/cash are non-IFRS measures and are explained in further detail on the Non-IFRS Measures section in this document.

Enquiries

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Full-year 2023 presentation webcast
The Company will host an investor and analyst presentation at 9:00 a.m. (UK time) on Monday, 29 April 2024, including a question-and-answer session, accessible through the link below:

Webcast link: https://shorturl.at/cdgxB
Event title: Jadestone Energy Full-Year 2023 Results
Time: 9:00 a.m. (UK time)
Date: 29 April 2024

To join the presentation by phone, please use the below dial-in details from the United Kingdom or the link for global dial-in details:

United Kingdom (Local): +44 20 3936 2999
United Kingdom (Toll-Free): +44 800 358 1035
Global Dial-In Details: https://shorturl.at/flot5
Access Code: 082963

ENVIRONMENT, SOCIAL AND GOVERNANCE ("ESG")

Jadestone is committed to being a responsible operator, that contributes to an orderly energy transition by helping to meet regional energy demand, whilst bringing positive social and economic benefits for its stakeholders, local communities and the people associated with its operations.

HSE performance

The Group's priority remains the health and safety of its staff, contractors and communities in which it operates, along with ensuring that any negative environmental impacts from operations are minimised.

The Group maintained strong safety performance despite elevated levels of activity and numerous and often challenging work fronts over 2023. Jadestone worked over 4.6 million man hours during 2023 (2022: 1.7 million work hours), with the year-on-year increase reflecting a full year of construction activity at the Akatara gas development. Consequently, the total recordable injury rate ("TRIR") of 0.86 was significantly lower than in previous years, and comparable with the International Association of Oil & Gas Producers ("IOGP") performance. Overall, the Group had zero lost time injuries ("LTIs"), as well as no material environmental incidents[1].

An excellent safety record was achieved at the Akatara gas development project site. The EPCI[2] contract was over 90% complete at 2023 year end, with over 3.28 million manhours worked without an LTI whilst undertaking higher risk activities such as major foundation works, pipe rack and storage tanks construction and well workovers. Jadestone continually engaged with the project's EPCI contractor to ensure that robust HSE management practices were implemented and monitored throughout the year.

Following the earlier reported incident at Montara in 2022, the General Direction relating to the Montara Venture FPSO tanks, which was put in place in September 2022, was lifted in February 2023. This followed completion of an independent review of Jadestone's remediation plans and operational readiness for the FPSO, which enabled production to re-commence gradually in March 2023. The Prohibition Notice that was issued in June 2022 is expected to remain open until each tank within the FPSO that can contain oil has been inspected and a technical file note demonstrating its fitness for service has been issued to NOPSEMA. Jadestone is currently methodically executing a tank restoration program, which resulted in 6 centre, 5 centre, 5 port, 5 starboard and both slops tanks being removed from the Prohibition Notice during 2023. Work is ongoing on the remaining tanks and once all are completed, the Prohibition Notice is expected to be fully lifted. Jadestone continues to engage closely and transparently with the regulator about the progress of the inspection work. The NOPSEMA Level 4 investigation into the 2C loss of containment is ongoing.

Net Zero interim targets

Jadestone's strategy for maximising reserves from existing producing oil and gas fields explicitly precludes frontier exploration and new greenfield development, a position that is in line with the IEA's Net Zero Emissions by 2050 Scenario. The Group is well positioned to benefit from the energy transition as a responsible steward of mid-life assets divested by larger companies, committed to upholding climate targets and executing its Net Zero by 2040 pledge.

In line with the previously communicated timetable, Jadestone announced its interim greenhouse gas ("GHG") emissions reduction targets in December 2023[3]. The Company has committed to reduce absolute Scope 1 and 2 GHG emissions from its operated assets by 20% by 2026 and by 45% by 2030 (from 2021 levels).

The interim targets will be achieved through a combination of measures, ranging from operational GHG reductions, including minimising flaring as well as reliance on carbon credits within the regulatory schemes of Jadestone regions. For further details, refer to Jadestone's 2023 Annual Report as well as Sustainability Report, which will be published by the end of May 2024.

[1] Defined as events leading to minor effect, recovery in weeks to months or higher as per Group's risk matrix.

[2] Engineering, Procurement, Construction and Installation.

[3] The detail of this announcement can be viewed on Jadestone's website.

In 2023, the Group's Scope 1 GHG emissions from operated sites were 469 kt of CO_2-e, slightly below the previous year (2022: 489 kt of CO_2-e). Levels of GHG emissions were significantly below forecast and reflected the downtime at Montara until late March 2023 and then during August 2023 as FPSO operations were gradually restored following tank repair works. Jadestone's indirect, Scope 2 GHG emissions from the consumption of purchased electricity across its offices and warehouses account for less than 1% of its total Scope 1 and 2 emissions combined. Jadestone does not consume any purchased electricity at any of its operated sites.

Governance

Jadestone's Board has undergone a number of changes during 2023 and the first quarter of 2024 with the longer-term objective to ensure that the Board is sized appropriately to the Company's scale and ambition, while maintaining the right capabilities and adhering to corporate governance standards.

On 18 October 2023, the Company announced the appointment of Gunter Waldner as a non-executive director. Mr. Waldner will stand for election at the Company's 2024 Annual General Meeting. Mr. Waldner was nominated as a non-executive director by the Company's largest shareholder, Tyrus Capital S.A.M. and funds managed by it ("Tyrus"), pursuant to the relationship agreement entered into by the Company and Tyrus in November 2018. Mr. Waldner brings significant knowledge of and experience in corporate finance and acquisition strategy.

On 25 January 2024, the Company announced the appointment of Joanne Williams as an independent non-executive director. Ms. Williams is a reservoir engineer with more than 25 years' experience in technical and executive roles. Ms. Williams is Chair of both the HSEC Committee and the Montara Technical Committee, and a member of the Audit Committee.

On 25 March 2024, the Company announced the appointment of Adel Chaouch as an independent non-executive director. Mr. Chaouch possesses significant upstream operations and executive experience. On 25 March 2024, the Company also announced the resignation of (i) Lisa Stewart as an independent non-executive director and (ii) Robert Lambert as an independent non-executive director.

On 27 March 2024, the Company announced the resignation of Dennis McShane as an independent non-executive director and Chair of the Board.

Also on 27 March 2024, the Company announced the election of Adel Chaouch as Chair of the Board. Dr. Chaouch is Chair of the Governance and Nomination Committee, and a member of both the Remuneration Committee and the HSEC Committee.

As previously announced, Iain McLaren has signalled an intention to step down as an independent non-executive director and Chair of the Audit Committee once a replacement has been appointed. The Board is progressing the recruitment of an appropriate candidate.

OPERATIONAL REVIEW

Producing Assets

Australia

Montara Project

The Montara Project, in production licences AC/L7 and AC/L8, is located 254 km offshore Western Australia, in water depth of approximately 77 metres. The Montara Project comprises three separate fields being Montara, Skua and Swift/Swallow, which are produced through an owned FPSO, the Montara Venture.

As at 31 December 2023, the Montara assets had proven plus probable reserves of13.6 mmbbls (31 December 2022: 18.5 mmbbls), 100% net to Jadestone. The year-on-year change in reserves at Montara is explained by production in the year (1.3 mmbbls) and a 3.5 mmbbls downgrade to reflect revisions to well performance, timing and nature of future infill drilling activity, and higher anticipated operating costs over life of field.

The fields produce light sweet crude (42^{o} API, 0.067% mass sulphur), which typically sells for average Dated Brent plus the average Tapis differential in the month of lifting. The premium in 2023 ranged between US$1.36/bbl to US$6.59/bbl, with an average premium of US$3.82/bbl. The most recent lifting in March 2024 was agreed at a premium of US$3.88/bbl.

Production from the Montara fields was shut in between August 2022 to March 2023 for storage tank inspection, maintenance and repair work following a small release of oil to sea in June 2022 and a further tank defect encountered in August 2022.

Following lifting of the General Direction issued by NOPSEMA in September 2022 and the completion of tank inspection and repair activities, as well as scheduled four-yearly maintenance activities, a phased production restart campaign commenced late in March 2023.

commenced late in March 2023.

On 29 July 2023, production at Montara was temporarily shut in following a hydrocarbon gas alarm in ballast water tank 4S. Production restarted on 1 September 2023 with tank 6C. Inspections identified the location of a small defect between tank 4S and oil cargo tank 5C, with the repairs of both tanks completed in Q1 2024 and returned to service thereafter.

On 4 October 2023, pressure was lost from the A annulus in the Skua-11 well, likely as a result of gas in the annulus escaping from a shallow leak point. The well was immediately shut in. A replacement operation, which includes a sidetrack to target volumes associated with Skua-11 and additional reserves in the vicinity is currently being planned and is expected to commence in Q4 2024.

Montara production averaged 3,655 bbls/d in 2023 (2022: 4,227 bbls/d), lower compared to previous year due to facility constraints caused by the separator limitations from March to July 2023 and the limited storage tank capacity on the FPSO due to the repair and maintenance activities referenced above.

There were five liftings in 2023, resulting in total sales of 1.2 mmbbls of crude oil compared to 1.7 mmbbls from the same number of liftings in 2022.

Stag oilfield

The Stag oilfield, in production licence WA-15-L, is located 60 km offshore Western Australia in a water depth of approximately 47 metres.

As at 31 December 2023, the field contained total proved plus probable reserves of 11.1 mmbbls (31 December 2022: 12.1 mmbbls), 100% net to Jadestone. The majority of the year-on-year change in reserves was explained by production during the year.

The Stag oilfield produces heavy sweet crude (18° API, 0.14% mass sulphur), which historically sells at a premium to Dated Brent. The premium in 2023 ranged between US$10.10/bbl and US$19.10/bbl with an average premium of US$ 13.03/bbl. The most recent lifting in March 2024 was agreed at a premium of US$15.88/bbl.

Production was 2,672 bbls/d in 2023 compared to 2,176 bbls/d in 2022. This increase was predominately due to the completion of the Stag 50H and 51H drilling campaign in November 2022.

There were four liftings in 2023 for total sales of 1.0 mmbbls, compared to 0.8 mmbbls in 2022 from the same number of liftings.

The Group made an impairment charge of US$17.4 million to Stag's oil and gas properties as at 31 December 2023, following an annual impairment assessment performed and identified that the VIU of the operating asset is lower than the carrying amount (see Financial Review section in this document).

North West Shelf Project

The Cossack, Wanaea, Lambert and Hermes oil fields (the"CWLH Assets") are located 115km offshore Western Australia in production licences WA-3-L, WA-9-L, WA-11-L and WA-16-L situated in a water depth of approximately 80 metres.

As at 31 December 2023, the CWLH Assets contained total proved plus probable reserves of 6.8 mmbbls (31 December 2022: 5.1 mmbbls), net to Jadestone. The year-on-year increase reflects the outperformance of the CWLH assets during 2023, with higher uptime and lower decline rates incorporated into the end-2023 reserves assessment, with asset life now extending to 2035 (from 2031) as a result. The end-2023 CWLH Assets reserves figure above does not include the recent doubling of the Group's interest, which is described below.

On 14 November 2023, the Group executed a sale and purchase agreement with Japan Australia LNG (MIMI) Pty Ltd (the "Seller"), to acquire the Seller's non-operated 16.67% working interest in the CWLH Assets, for a total initial cash consideration of US$9 million, and certain subsequent Abandonment Trust Payments (the "Acquisition").

The Acquisition was completed on 14 February 2024, with a net receipt to the Group from the Seller of US$6.3 million, reflecting the accumulated economic benefits of the CWLH assets for the period from the effective date of 1 July 2022 to completion. As a result, the Group's non-operated working interest in the CWLH assets increased to 33.33%, from 16.67%.

On 9 February 2024, the US$6.3 million net receipt from the Seller and US$35.7 million from Jadestone were paid into the CWLH abandonment trust fund, in aggregate satisfying the initial US$42.0 million abandonment funding requirement required under the terms of the Acquisition. The second US$23.0 million instalment into the abandonment trust fund is payable on NOPTA's approval of the accession documents, which is expected in Q2 2024. The final instalment of up to US$37.0 million will be paid into the abandonment trust fund by 31 December 2024.

Contribution to Group production was 1,896 bbls/d in 2023 compared to 383 bbls/d in 2022 on an annualised basis, due to the timing of the acquisition. The average production from the completion date of 1 November 2022 to 31 December 2022 was 2,290 bbls/d, net to Jadestone's working interest.

Jadestone lifted one cargo in 2023 for total sales of 0.7 mmbbls, compared to 0.7 mmbbls in 2022, also from one lifting.

Malaysia

Operated: PM 323 and PM 329, PM 318 and AAKBNLP PSCs

The PenMal Assets consist of two operated PSCs, which comprise a 70% interest in PM329 PSC, containing the East Piatu field, and a 60% interest in PM323 PSC, which contains the East Belumut, West Belumut and Chermingat fields.

Additionally, the Group assumed 100% working interests in PM318 and AAKBNLP PSCs (the "PNLP Assets") after taking over operatorship in April 2023 following the decision of the previous operator to withdraw from the licences. As a result, the Group acquired the rights over the 50% of abandonment cess fund and assumed the remaining 50% of asset restoration obligations under the PNLP Assets. As part of the takeover, the previous operator paid the Group for a sum representing its share of future wells preservation activities and decommissioning costs. The Group believes that the PNLP Assets have significant reserve and resource potential. Jadestone is currently overseeing operations and maintenance in shut-in mode. In June 2023, the Group submitted a business value proposition to PETRONAS outlining plans to redevelop the PNLP Assets and resume production. The PNLP Assets were included in the Malaysia Bid Round Plus ("MBR+") process in October 2023 and renamed as the "Puteri Cluster". The reinstatement of production and further development of the Puteri Cluster by the Group is subject to retaining the licence as part of the MBR+ process. The Group has submitted a bid for the Puteri Cluster, with the results of the MBR+ process anticipated in mid-2024.

All four PSCs are located approximately 230km northeast of Terengganu in shallow water.

As at 31 December 2023, PM323 and PM329 PSCs contained total proved plus probable reserves of 9.2 mmboe (2022: 8.9 mmboe), net to Jadestone. The year-on-year increase can be primarily explained by a reserve upgrade at PM323 PSC following the successful infill drilling campaign in late 2023 and offset by production during the year.

The PenMal Assets produce light sweet crude that is blended to Tapis grade (43^{O} API, 0.04% mass sulphur). The premium in 2023 ranged between US$2.72/bbl to US$5.63/bbl with an average premium realised of US$4.38/bbl. The most recent lifting in March 2024 was agreed at a premium of US$4.16/bbl.

Production in 2023 was 3,664 bbls/d of oil and 3,744 mscf/d of gas, or 4,288 boe/d, net to Jadestone's working interest, compared to 3,884 bbls/d of oil and 4,908 mscf/d of gas, or 4,702 boe/d in 2022. The year-on-year decrease is due to natural production decline at the PM329 PSC only being partly offset by the initial contribution of the new PM323 infill wells drilled in late 2023, and no production from the PNLP Assets reflecting the current shut-in mode.

The East Belumut (PM323 PSC) infill campaign, which commenced in August 2023, was very successful, with first oil achieved two months earlier than expected. By adding four new horizontal oil producers, field production was quadrupled and exceeded target, with incremental gross oil production of c.8,000 bbl/d. The infill campaign delivered incremental gross reserves of 4.2 mmbbls, including 1.3 mmbbls from the existing wells on the field after the economic limit was extended by c.3 years.

There were nine liftings from the PenMal Assets in 2023, resulting in total oil sales of 0.8 mmbbls and total gas sales of 1.4 mmscf, compared to total oil sales of 0.8 mmboe and total gas sales of 1.8 mmscf from 13 liftings in 2022.

Thailand

<u>APICO LLC (Sinphuhorm gas field and Dong Mun gas discovery)</u>

On 23 February 2023, the Group closed the acquisition of interests in three legal entities, which collectively own a 9.52% non-operated interest in the producing Sinphuhorm gas field and a 27.2% interest in Dong Mun gas discovery onshore north-east Thailand. The acquisition included a 27.2% interest in APICO LLC, which operates the Sinphuhorm concessions (E5N and EU1) and Dong Mun (L27/43).The cash consideration was US$27.8 million, based on an effective date of 1 January 2022.

As at 31 December 2023, the Sinphuhorm Assets contained proved plus probable reserves of 3.9 mmboe, net to Jadestone.

The Group's 9.52% non-operated working interest in the Sinphuhorm Assets enables the Group to exercise significant, being the power to participate in the financial and operating policy decisions, but not control or joint control over the assets' day-to-day operations. Therefore, the Group does not recognise its share of revenues and production costs, instead recognising dividend income when received. The Group received US$3.7 million of dividends in 2023.

Average production since the date of acquisition was 1,450 boe/d, contributing 1,303 boe/d to Group annual production in 2023.

Pre-production Assets

Indonesia

<u>Lemang PSC</u>

The Lemang PSC is located onshore Sumatra, Indonesia. The PSC contains the Akatara field, which has been de-risked with 11 wells drilled into the structure, plus three years of oil production history, up until the field ceased oil production in December 2019. Jadestone is redeveloping Akatara to supply gas, condensate and LPGs for local and regional use.

The Akatara gas field has been independently estimated to contain 2P gross reserves (pre local government back-in rights) of 81.4 bcf of sales gas, 2.8 mmbbls of condensate and 9.5 mmboe of LPG, equating to a combined 25.9 mmboe of reserves. Jadestone has a 100% interest in the Lemang PSC, with the local government retaining a back-in right for a 10% participating interest. The Group expects the local government to take the 10% interest from its back-in rights, a process which is currently going through a due diligence phase.

During 2023, the Group's primary focus was on the civil foundation works, control and electrical buildings, erection of the

LPG, condensate and fire water tanks, and the main pipe-rack. This was followed by installation of the static and rotating equipment, installation of piping, and electrical/instrumentation cables, including the sales gas pipeline, flowlines modification and the gas metering station. By the end of December 2023, all of the key long-lead items had arrived on site.

Currently, the Group is focused on testing all equipment, testing, cleaning and reinstatement of interconnecting pipe, electrical and instrument testing at both the gas plant and metering station, and the hydrotesting of the gas pipeline. Overall progress of the project had reached 95.72% completion at the end of March 2024. Pre-commissioning and commissioning activities commenced in November 2023 and continued into early Q1 2024 for utility systems, with further progression towards commissioning for the process system. Commercial production remains on track to start in Q2 2024.

In June 2023, the Group successfully reactivated two wells from the prior oil development on the Akatara field. During testing, one well achieved a maximum flow rate of approximately 9 million cubic feet per day (mmcf/d), with data from the well test supporting the current Akatara 2P reserves estimate. The well is designated to supply pre-commissioning and commissioning gas for the AGPF, while the second well is intended for use as an injector/disposal well.

A campaign with a 550 HP rig to work-over the planned five wells commenced in Q1 2024. Currently, four out of five well workovers have been completed and tested at an aggregate stabilised rate of c.30 mmcf/d, ready to deliver the gas production required to fulfil the daily contract quantity under the gas sales agreement.

Vietnam

Block 51 and Block 46/07 PSCs

Jadestone holds a 100% operated working interest in the Block 46/07 and Block 51 PSCs, both in shallow water in the Malay Basin, offshore southwest Vietnam.

The two contiguous blocks hold three discoveries: the Nam Du gas field in Block 46/07 and the U Minh and Tho Chu gas/condensate fields in Block 51, with aggregate 2C contingent resources of 93.9 mmboe.

Throughout 2023, the Group negotiated a gas sales heads of agreement ("HoA") with Petrovietnam Gas Joint Stock Corporation ('PV Gas'). The key terms were finalised after receiving approval from PV Gas, Petrovietnam, and Jadestone, with the HoA signed on 25 January 2024.

The HoA enables the submission of an updated Nam Du/U Minh Field Development Plan for approval, which is required before a final investment decision can be taken and commercialisation of this potential resource advanced.

Exploration phase two of the Block 46/07 PSC includes a commitment to drill one exploration well. Jadestone proposes to drill this well in conjunction with drilling the gas production wells for the Nam Du field development and to utilise the well as a future gas producer via the Nam Du/U Minh processing facilities. Exploration phase two is due to expire on 29 June 2024. The Group has submitted a request to Petrovietnam to extend the drilling deadline to align the timing of the commitment well with the Nam Du/U Minh project schedule. This approach is consistent with previous extensions granted for the PSC exploration phase two.

The Tho Chu discovery in Block 51 was under a suspended development area status. The Company is working with Petrovietnam and other government entities to obtain a suspension of the relinquishment obligation for Block 51.

Reserves and resources

Total 2P Reserves (net, mmboe)

	Australia	Malaysia[2]	Indonesia[2]	Thailand	Total Group
Opening balance, 1 January 2023	**35.6**	**8.9**	**20.3**	**0.0**	**64.8**
Acquisitions	-	-	-	4.2	**4.2**
Technical revisions	(1.0)	1.9	3.0	0.2	**4.1**
Production	(3.0)	(1.6)	-	(0.5)	**(5.1)**
Ending balance, 31 December 2023	**31.6**	**9.2**	**23.3**	**3.9**	**68.0**

As at 31 December 2023, the Group had proved plus probable oil reserves ("2P Reserves") of 68.0 mmboe, a 5% increase compared with 31 December 2022 and representing 164% 2P reserve replacement during the year.

2P reserves of 4.3 mmboe were booked on closing of the Sinphuhorm acquisition in February 2023. There was a reserve upgrade at the CWLH fields offshore Australia due to better than expected asset performance during the year, in turn extending field life from 2031 to 2035. Reserves also increased at the PM323 field offshore Malaysia due to the successful infill drilling campaign in the second half of 2023. An additional 3.0 mmboe of 2P reserves were booked at the Akatara field, representing the volumes committed under a further gas sales agreement negotiated during the year. These positive moves were balanced by a 3.5 mmbbls reduction in reserves at Montara, due to the forecast of higher operating costs over the life of the field, and a small negative revision at the PM329 asset offshore Malaysia. Jadestone completed the acquisition of an additional 16.67% interest in the CWLH fields, adding a further 6.8 mmboe of 2P Reserves at closing, after the period end and was therefore not included in end-2023 reserves calculation.

ERCE independently evaluated the Group's year-end 2023 reserves.

Total 2C Contingent Resources[3] (net, mmboe)

	Australia	Malaysia	Indonesia[2]	Thailand	Vietnam[2]	Total Group

Opening balance, 1 January 2023	**6.5**	**-**	**3.9**	**0.0**	**93.9**	**104.3**
Acquisitions	-	-	-	2.5	-	2.5
Transfer to 2P reserves	(2.4)	-	(3.0)	-	-	(5.4)
Technical revisions	1.1	1.2	-	1.9	-	4.2
Ending balance, 31 December 2023	**5.1**	**1.2**	**0.9**	**4.4**	**93.9**	**105.6**

The Group's best case contingent resources ("2C resources") increased slightly from 104.3 mmboe in 2022 to 105.6 mmboe in 2023. The partial reclassification of Akatara and CWLH contingent resources to 2P reserves was more than offset by the inclusion of the Group's share of future (2025) infill targets at PM323 and PM329, contingent resources associated with a potential life extension of Sinphuhorm field life and the CWLH fields, and contingent resources associated with the Dong Mun discovery onshore Thailand (acquired with the interest in the Sinphuhorm field).

[1] Proven and Probable Reserves for Jadestone's assets have been prepared in accordance with the June 2018 SPE/WPC/AAPG/ SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting.

[2] Assumes oil equivalent conversion factor of 6,000 scf/boe.

[3] Contingent Resources based on ERCE estimates as at 31 December 2022, except for Vietnam 2C resources which are based on ERCE Competent Person's Report effective 31 December 2017.

FINANCIAL REVIEW

The following table provides select financial information of the Group, which was derived from, and should be read in conjunction with, the consolidated financial statements for the year ended 31 December 2023.

USD'000 except where indicated	2023	2022 Restated*
Sales volume, barrels of oil equivalent (boe)	3,862,741	4,326,770
Production, boe/day[1]	13,813	11,487
Realised oil price per barrel of oil equivalent (US$/boe)[2]	87.34	103.85
Realised gas price per thousand standard cubic feet (US$/mscf)	1.53	1.63
Revenue[3]	309,200	421,602
Production costs	(232,772)	(250,300)
Adjusted unit operating costs per barrel of oil equivalent (US$/boe)[4]	37.24	37.49
Adjusted EBITDAX[4]	90,647	162,329
Unit depletion, depreciation & amortisation (US$/boe)	14.14	10.74
Impairment of assets	(29,681)	(13,534)
(Loss)/Profit before tax	(102,766)	63,193
(Loss)/Profit after tax	(91,274)	9,237
(Loss)/Earnings per ordinary share: basic & diluted (US$)	(0.18)	0.02
Operating cash flows before movement in working capital	36,499	158,548
Capital expenditure	115,882	82,876
Net (debt)/cash[4]	(3,596)	123,329

Benchmark commodity price and realised price

The actual average realised price in 2023 decreased in line with the benchmark price, which decreased by 16% to US$87.34/bbl, from US$103.85/bbl in 2022. The primary factor was the downturn in the benchmark Brent price, which fell by 18% to US$82.64/bbl compared to US$101.32/bbl in 2022. The average realised premium for the year was US$5.58/bbl, compared to US$7.81/bbl in 2022, generally following the lower average Brent price. The Stag premium averaged US$13.03/bbl (2022: 22.78/bbl), Montara premium was US$3.82/bbl (2022: US$4.70/bbl) and PenMal operated assets premium came in at US$4.38/bbl (2022: US$6.67/bbl).

*Restatements explained in Note 50 of the Group's consolidated financial statements.

[1] Production includes the Sinphuhorm Asset gas production in accordance with Petroleum Resource Management Systems guidelines, however in accordance with IAS 28 the investment is accounted for as an associated undertaking and the Group only recognises dividends received. Accordingly, the revenue and production costs from the Sinphuhorm Assets are excluded from the Group's financial results.

from the Group's financial results.

2 Realised oil price represents the actual selling price inclusive of premiums.

3 Revenue in 2023 of US$309.2 million consist of a hedging loss of US$10.3 million from the commodity swap contracts entered into in support of the RBL facility.

4 Adjusted unit operating cost per boe, adjusted EBITDAX and net cash are non-IFRS measures and are explained in further detail on the Non-IFRS Measures section in this document.

Production and liftings

The Group achieved average production of 13,813 boe/d in 2023, an increase from 11,487 boe/d in 2022. The overall increase was as a result of the following key factors:

- Higher annualised production at the CWLH Assets of 1,896 bbls/d for the full year in 2023 compared to two months in 2022 of 383 bbls/d;
- Acquisition of the Sinphuhorm Assets in February 2023 contributing to annualised production of 1,303 boe/d; and
- Stag production increased by 496 bbls/d attributable to the additional output from the successful drilling and completion of 50H and 51H wells in November 2022.

The increase was partly offset by:

- Lower production from Montara by 572 bbls/d as a result of the facility constraints caused by the separator limitations from March to July and tank tops arising from the limited storage tank capacity on the FPSO ; and
- Reduced production from the PenMal Assets by 414 bbls/d due to higher unplanned downtime of the Chermingat platform combined with natural field decline.

Throughout the year, the Group executed 19 liftings, a decrease from the 22 liftings in 2022, leading to oil sales totaling 3.6 million barrels (mmbbls), down from 4.0 mmbbls in 2022. This reduction in lifted volumes was caused by lower production levels at the Montara and PenMal Assets.

The Group recorded a sale of 1,366.5 mmscf of gas from the PenMal Assets, compared to 1,791.1 mmscf of gas in 2022.

Revenue

The Group generated net revenue after the effect of hedging of US$309.2 million in 2023, a decrease of 24% compared to 2022 of US$421.6 million. The decrease of US$112.4 million was predominately due to:

- Lower average realised prices in 2023 of US$87.34/bbl (2022: US$103.85/bbl), resulting in decreased revenue of US$66.6 million;
- A hedging loss of US$10.3 million incurred from thecommodity swap contracts entered into following the execution of the RBL facility;
- A reduction in lifted volumes by 0.4 mmboe year-on-year resulting in decreased revenue of US$34.4 million; and
- PenMal Assets generating lower gas revenue of US$2.0 million compared to US$3.1 million in 2022.

Production costs

Production costs decreased by 7% in 2023 to US$232.8 million, from US$250.7 million in 2022, amounting to a decrease of US$17.5 million. The reduction was predominately due to the following factors:

	2023	2022 Restated*	Variance	Note
	USD'000	USD'000	USD'000	
Operating costs	98,723	74,283	24,440	(i)
Supplementary payments and royalties	16,056	26,381	(10,323)	(ii)
Workovers	17,562	10,190	7,372	(iii)
Logistics	34,109	31,895	2,214	(iv)
Repairs and maintenance	55,572	60,174	(4,602)	(v)
Decommissioning expenses	12,545	-	12,545	(vi)
Underlift, overlift and crude inventories movement	(9,297)	39,036	(48,333)	(vii)
Tariffs and transportation costs	7,502	8,341	(839)	(viii)
	232,772	**250,300**	**(17,526)**	

(i) Overall operating costs increased by US$24.4 million to US$98.7 million in 2023, compared to US$74.3 million in 2022, due to:

- Operating costs at Montara and Stag increased by US$20.8 million (2023: US$77.0 million; 2022: US$56.2 million), primarily due to US$14.3 million related to the hire of a crude tanker to compensate for reduced Montara FPSO tank capacity and US$1.0 million incurred for the non-recurring disposal of NORMs (naturally occurring radioactive material). Stag tanker costs increased by US$5.8 million compared to 2022 reflecting higher tanker rates in 2023;
- A full year of operations at the CWLH Assets, compared to two months in 2022, resulted in an increase in operating costs by US$13.6 million;
- Operating costs at the PenMal Assets decreased by US$10.0 million to US$5.2 million in 2023, down from US$15.2 million in 2022. This reduction was primarily due to reduced chemical consumption at the operated

assets. Additionally, the decrease was associated with the continued suspended production at the PNLP Assets in 2023;

(ii) Supplementary payments and royalties decreased by US$10.3 million in 2023 totalling US$16.1 million, compared to US$26.4 million in 2022. The supplementary payments at the PenMal Assets decreased by US$14.0 million to US$10.5 million (2022: US$24.5 million) due to lower realised price compared to 2022, as the payments are based on the differential between the realised price and the escalated PSC base price. The decrease was partly offset by higher royalties paid by the CWLH Assets for the levy on the wellhead value for a primary production licence in 2023 of US$3.5 million (2022: US$0.8 million);

(iii) Workover costs rose by US$7.4 million to US$17.6 million compared to US$10.2 million in 2022. The increase was mainly due to the completion of 10 workovers at Stag in 2023, including nine standard routine workovers and one complex well integrity repair, compared to four standard routine workovers in 2022. The increase was partially mitigated by a decrease in workover costs of US$2.4 million at Montara;

(iv) The increase of US$2.2 million in logistical costs was mainly driven by the PenMal Assets, which was attributable to cargo handling charges resulting from a higher charge rate and higher frequency of personnel mobilisation/demobilisation and material/equipment costs at the operated assets;

(v) Repair and maintenance ("R&M") costs decreased by US$4.6 million to US$55.6 million in 2023 compared to US$60.2 million in 2023. Montara and Stag incurred higher R&M in 2022 by US$5.8 million mainly for Skua-11 repair works, solar engine change out and emergency tank repairs. The year-on-year reduction at Montara and Stag was partly offset by higher R&M at the PenMal Assets of US$1.2 million in 2023 for the repair of a gas turbine generator at the PM329 PSC;

(vi) The PenMal Assets incurred US$12.5 million cost, net to Jadestone's share, for decommissioning work scope performed by the previous operator of the PNLP Assets on the Bunga Kertas FPSO;

(vii) The variance of US$48.3 million is mainly drivenby the first time recognition of the overlift position (US$34.0 million) in 2022. The overlift at the CWLH Assets as at the end of 2023 generated a credit to production costs of US$0.4 million compared to a charge of US$33.6 million in 2022 reflecting the first time recognition of overlift at acquisition in November 2022.

Montara and Stag ended the year with a combined increase in crude inventories of 120,580 bbls compared to the beginning of 2023, generating a credit of US$6.2 million. In comparison, at the end of 2022, Montara and Stag had a lower combined inventories on hand, resulting in a decrease of 183,422 bbls compared to beginning of 2022, generating a charge of US$3.4 million.

The underlift at the PenMal Assets created a credit to production cost of US$2.7 million compared to a charge of US$2.0 million as a result of the overlift position at 2022 year end; and

(viii) Tariffs and transportation costs were incurred at Montara, Stag and the PenMal Assets. The year-on-year movement is not significant.

Unit operating costs per barrel of oil equivalent (boe) at US$37.24/boe were largely unchanged in 2023 compared to US$37.49/boe in 2022 (refer to the Non-IFRS measures section below in this document).

*Restatements explained in Note 50 of the Group's consolidated financial statements.

Depletion, depreciation and amortisation ("DD&A")

DD&A charges were US$76.1 million during the year, compared to US$61.6 million in 2022, with the increase predominately due to the higher production at Stag and a full year production at the CWLH Assets, resulting in an increase of US$8.1 million and US$3.0 million, respectively. Additionally, the PenMal Assets recorded a higher DD&A charge by US$7.0 million compared to 2022 due to the drilling campaign undertaken at PM323 PSC during the second half of 2023, resulting in an increase of production during Q4 2023. These increases were partly offset by a crude inventory credit of US$4.2 million (2022: charge of US$2.9 million) as both Montara and Stag ended the year with higher crude inventories on hand compared to beginning of 2023, whereas both assets had a lower crude inventory on hand at the end of 2022 compared to beginning of year.

Depreciation of the Group's right-of-use assets increased to US$15.3 million in 2023 from US$13.0 million in 2022, primarily due to the extension of the Group's helicopter lease and Montara warehouse lease for three years and two years, respectively, plus a two-year lease for a Montara support vessel replacing an expired lease.

The depletion cost on a unit basis was US$14.14/boe in 2023 (2022: US$10.74/boe), due to higher combined depletion costs per unit at both Montara and Stag in 2023 at US$21.68/bbl (2022: US$17.35/bbl)due to an increase in the asset retirement obligations ("ARO") and the addition of capital expenditure from drilling of the 50H and 51H wells at Stag in Q4 2022. The unit depletion costs in 2023 for the PenMal Assets was US$6.40/boe compared to US$1.76 /boe in 2022, due to the drilling campaign undertaken at PM323 PSC during H2 2023.

Staff costs

Total staff costs in 2023 were US$56.2 million, comprising US$26.0 million (2022: US$26.1 million) in relation to offshore employees, recorded under production costs, and US$30.2 million (2022: US$29.2 million) for office-based employees. The average number of employees during the year was 409 (2022: 369), with the additional staff costs and headcount year-on-year mainly at Indonesia for the ramp up of activities at the Akatara development project. The remaining increase come from the operations in Australia and Malaysia, which have seen marginal expansion across the assets.

Other expenses

Other expenses increased in 2023 to US$22.8 million (2022: US$22.3 million). The variance of US$0.5 million was predominately due to:

	2023 USD'000	2022 USD'000	Variance USD'000	Note
Non-recurring corporate costs	3,602	1,119	2,483	(i)
Recurring corporate costs and other expenses	11,742	9,431	2,311	(ii)
Change in provision - Lemang PSC contingent payments	-	7,333	(7,333)	(iii)
Allowance for slow moving inventories	655	3,768	(3,113)	(iv)
Assets written off	5,114	212	4,902	(v)
Net foreign exchange loss	1,728	442	1,286	(vi)
	22,841	**22,305**	**536**	

(i) An increase in non-recurring costs by US$2.5 million compared to 2022. In 2023, the Group incurred non-recurring costs including advisory and consulting fees for business development of US$2.2 million, an internal re-organisation for US$0.8 million, US$0.4 million for the equity fundraise in June 2023 and an aggregate of US$0.2 million for the Interim Facility, RBL facility and commodity swap contracts. In comparison, the Group incurred total non-recurring costs of US$1.1 million in 2022 related to the acquisition of CWLH Assets, business development and other one-off projects;

(ii) An increase in corporate costs and other expenses by US$2.3 million to US$11.7 million in 2023 (2022: US$9.4 million) across all operating countries;

(iii) The 2022 costs included the recognition of additional contingent payments related to the future Dated Brent prices and Saudi CP prices associated with the Lemang PSC of US$7.3 million. Following the 2023 year-end assessment, these contingent payments were derecognised with the associated credit booked in other income (see note below). The Group did not recognise new contingent payments in 2023;

(iv) The Group provided an allowance for slow moving inventories of US$0.7 million during the year, compared to US$3.8 million in 2022, following the assessment performed.

(v) Assets written off amounted to US$5.1 million in 2023 (2022: US$0.2 million), which included the write-off of the non-depletable oil and gas properties at Montara for US$3.1 million following the cancellation of a capital project for the preparation of Skua-12 well, and the write-off of obsolete material and spares for US$2.0 million. In 2022, the Group wrote off US$0.2 million for plant and equipment associated with its New Zealand operations following the withdrawal from Maari acquisition; and

(vi) Net foreign exchange loss of US$1.7 million in 2023 (2022: US$0.4 million) mainly arising from the Group's receivables denominated in Malaysian Ringgit ("MYR") due to the volatility of MYR against USD towards the end of 2023.

Finance costs

Finance costs in 2023 were US$41.8 million (2022: US$11.4 million), an increase of US$30.4 million, predominately due to:

- Warrants expense of US$3.5 million arose from the warrants for 30 million ordinary shares received by Tyrus in connection with the underwriting debt facility in support of the June 2023 equity placing;
- ARO accretion expense increased by US$11.9 million to US$20.2 million compared to US$8.3 million in 2022, resulting from an increase in the ARO at Stag and Montara as assessed at year-end 2022;
- Upfront fees of US$2.7 million (2022: nil) and interest of US$1.0 million (2022: nil) were incurred in association with the equity underwrite debt facility and committed standby working capital facility executed with Tyrus Capital Events S.a.r.l.;
- RBL accretion expense of US$5.5 million (2022: nil) reflecting the time value of money and RBL commitment fees of US$0.3 million (2022: nil);
- Interest expense and other finance costs increased by US$3.6 million to US$3.7 million compared to US$0.1 million in 2022, mainly due to the interest expense and fees associated with the US$50.0 million Interim Facility (US$1.3 million) and relating to the RBL facility (US$1.2 million). Additionally, the Group incurred accretion expense of US$0.6 million generated from an Australian Tax Office repayment plan for corporate tax payments;
- Interest on lease liabilities increased by US$2.0 million to US$2.8 million compared to US$0.8 million in 2022, following the lease extensions for helicopters, vessel and warehouse at Montara; and
- Changes in fair value of contingent payments in 2023 of US$0.9 million, a US$1.0 million decrease compared to US$1.9 million in 2022.

Other income

The Group generated US$18.9 million of other income during 2023 compared to US$28.0 million in 2022, predominately due to:

- Interest income from the CWLH Assets decommissioning trust fund of US$2.9 million (2022: US$0.1 million) and US$1.0 million (2022: nil) from the placement of fixed deposits;
- Reversal of provisions associated with the Lemang PSC's contingent payments in 2023 of US$7.7 million being the derecognition of contingent payments associated with the Saudi CP and Dated Brent prices, as the trigger events are not expected to occur; and
- In 2022, other income included insurance claim receipts of US$18.0 million compensating for the loss of production at Montara related to drilling activities at the Skua-10/11 wells in 2021.

Share of result of associates

Since the acquisition of the Sinphuhorm Assets in February 2023, the Group recognised its share of profits amounting to US$2.6 million for the period up to 31 December 2023.

Impairment

During the year, the Group made an impairment to the Stag's oil and gas properties carrying value of US$17.4 million following the annual impairment assessment, which identified that the recoverable amount of the operating asset is lower than its carrying amount.

Additionally, the Group also recorded an impairment related to the PNLP Assets' oil and gas properties of US$12.3 million resulting from a revision of ARO estimates. The revised ARO is capitalised but immediately impaired because management does not currently anticipate future economic inflows from the PNLP Assets, given the uncertaintyregarding a potential restart of production. The Group fully impaired the PNLP Assets' oil and gas properties in 2022.

Taxation

The tax credit of US$11.5 million in 2023 (2022: US$54.0 million of tax charge) includes a current tax charge of US$10.8 million (2022: US$27.1 million) and a deferred tax credit of US$22.3 million (2022: deferred tax charge of US$26.9 million).

During the year, tax payments comprised US$5.3 million (2022: US$18.5 million) for Australian corporate taxes and US$1.7 million (US$1.1 million) for PRRT payments. Additionally, there were US$7.5 million (2022: US$15.7 million) in Malaysian petroleum income tax ("PITA") payments.

The weighted average effective tax rate for operating jurisdictions in Australia and Malaysia was negative 54% in 2023, reflecting losses incurred during the year, compared to 56% in 2022, which was attributable to profits generated during that year. There was an increase in the deferred tax asset during 2023, resulting from income tax credits as the trading losses are carried forward for offset against future taxable profits.

USD'000	2023	2022 Restated*
(Loss)/Profit before tax	(102,766)	63,193
Expected effective tax rate	54%	56%
Tax at the country level effective rate	**(55,494)**	**35,388**
Effect of different tax rates in loss making jurisdictions	13,975	13,934
Malaysia PITA tax losses on non-operated PSCs	10,060	8,742
Utilisation of PRRT credits	17,795	(21,661)
PRRT tax refund	1,735	(1,121)
Capital gain tax from acquisition of CWLH Assets	-	1,486
Australian decommissioning levy	-	336
Non-deductible expenses	399	938
Deferred tax permanent differences	2,155	9,217
PRRT permanent differences	(4,269)	7,032
Adjustment in respect to prior years	2,152	(335)
Tax (credit)/expense for the year	**(11,492)**	**53,956**

Australia taxes

The Australian corporate income tax rate is 30% and PRRT is 40%, with the latter being cash based and income tax deductible. The combined standard effective tax rate is 58%, with the actual effective tax rate of 42% in 2023 (2022: 46%) being lower predominately due to the utilisation of PRRT credits brought forward at Montara. Montara and the CWLH Assets have approximately US$3.8 billion (2022: US$3.5 billion) and US$493.4 million (2022: US$535.5 million) of unutilised PRRT credits, respectively. Both assets are not expected to incur any PRRT over their economic lives. There was an increase in the deferred tax asset during 2023, resulting from income tax credits as the trading losses are carried forward for offset against future taxable profits.

Malaysia taxes

Malaysian PITA is a PSC based tax on petroleum operations at the rate of 38%. There are no other material taxes in Malaysia.

*Restatements explained in Note 50 of the Group's consolidated financial statements.

RECONCILIATION OF CASH

US$'000		2023		2022 Restated*
Cash and cash equivalents at the beginning of year		**123,329**		**117,865**
Revenue	309,200		421,602	
Other operating income	6,574		26,485	
Production costs	(232,772)		(250,300)	
Staff costs	(29,431)		(28,247)	
General and administrative expenses	(17,072)		(10,992)	
Operating cash flows before movements in working capital		**36,499**		**158,548**
Movement in working capital		6,837		36,819
Placement of decommissioning trust fund for CWLH Assets		(41,000)		(41,000)
Net tax paid		(14,461)		(33,130)
Investing activities				
Purchases of intangible exploration assets, oil and gas properties, and plant and equipment[1]		(109,524)		(82,628)
Cash paid on acquisition of Sinphuhorm Assets		(27,853)		-
Dividends received from associate		3,842		-
Cash received on acquisition of CWLH Assets		-		5,750
Cash paid for acquisition of 10% interest of Lemang PSC		-		(500)
Other investing activities		4,451		881
Financing activities				
Net proceeds from issuance of shares		50,964		784
Shares repurchased		(2,084)		(16,070)
Repayment of lease liabilities		(14,400)		(13,914)
Total drawdown of borrowings		232,000		-
Repayment of borrowings		(75,000)		-
Repayment of costs and interests of borrowings		(13,260)		-
Other financing activities		(6,936)		(860)
Dividends paid		-		(9,216)
Total cash and cash equivalent at the end of year		**153,404**		**123,329**

*Restatements explained in Note 50 of the Group's consolidated financial statements.

[1] Total capital expenditure was US$115.9 million (2022: US$82.9 million), comprising total capital expenditure paid of US$109.5 million (2022: US$82.6 million), accrued capital expenditure of US$4.0 million (2022: US$0.3 million) and capitalisation of borrowing costs of US$2.4 million (2022: nil).

NON-IFRS MEASURES

The Group uses certain performance measures that are not specifically defined under IFRS, or other generally accepted accounting principles. These non-IFRS measures comprise adjusted unit operating cost per barrel of oil equivalent (adjusted opex/boe), adjusted EBITDAX, outstanding debt, and net cash.

The following notes describe why the Group has selected these non-IFRS measures.

Adjusted unit operating costs per barrel of oil equivalent (Adjusted opex/boe)

Adjusted opex/boe is a non-IFRS measure used to monitor the Group's operating cost efficiency, as it measures operating costs to extract hydrocarbons from the Group's producing reservoirs on a unit basis.

Adjusted opex/boe is based on total production cost and incorporates lease payments linked to operational activities, net of any income derived from those right-of-use assets involved in production. The calculation excludes factors such as oil inventories movement, underlift/overlift adjustments, inventory write-downs, workovers, and non-recurring repair and maintenance expenses, transportation costs, supplementary payments associated with the PenMal Assets, expenses related to non-operating assets, and DD&A. This definition aims to ensure better comparability between periods.

The adjusted production costs are then divided by total produced barrels of oil equivalent for the prevailing period to determine the unit operating cost per barrel of oil equivalent.

USD'000 except where indicated	2023	2022 Restated*
Production costs (reported)	232,772	250,300
Adjustments		
Lease payments related to operating activity[1]	16,155	13,687
Underlift, overlift and crude inventories movement[2]	9,297	(39,036)
Workover costs[3]	(17,562)	(10,190)
Other income[4]	(6,375)	(5,030)
Non-recurring operational costs[5]	(19,654)	-
Non-recurring repair and maintenance[6]	(1,773)	(13,761)
Transportation costs	(7,502)	(8,341)
PenMal Assets supplementary payments and Australian royalties[7]	(16,056)	(26,381)
PenMal non-operated assets operational costs[8]	(19,273)	(4,056)
Adjusted production costs	**170,029**	**157,192**
Total production (barrels of oil equivalent)	4,566,060	4,192,618
Adjusted unit operating costs per barrel of oil equivalent	**37.24**	**37.49**

[1] Lease payments related to operating activities are lease payments considered to be operating costs in nature, including leased helicopters for transporting offshore crews. These lease payments are added back to reflect the true cost of production.

[2] Underlift, overlift and crude inventories movement are added back to the calculation to match the full cost of production with the associated production volumes (i.e., numerator to match denominator).

[3] Workover costs are excluded to enhance comparability. The frequency of workovers can vary significantly, across periods.

[4] Other income represents the rental income from a helicopter rental contract (a right-of-use asset) to a third party.

[5] Non-recurring operational costs mainly related to costs incurred at Montara being interim tanker storage temporarily employed as a result of the repair work relating to the storage tanks of the FPSO, diesel fuel consumption by the FPSO during production shutdown and to power the reinjection compressor during production start-up. The Group also incurred charges associated with short lifting a cargo and delivery delays.

[6] Non-recurring repair and maintenance costs in 2023 predominately related to the repair of a gas turbine generator at the PenMal Assets PM329 PSC. The costs during 2022 predominately related to Montara Skua-11 repair works, gas compressor solar engine change out and tank repairs following the shut-in of Montara in August 2022.

[7] The supplementary payments are required under the terms of PSCs based on Jadestone's profit oil after entitlements. The Australian royalties are related to local decommissioning cost recovery levy plus royalties payable to the local state government arising previously from the acquisition of the CWLH Assets.

[8] PenMal non-operated assets operational costs in 2023 refer to the operating costs incurred at the PNLP Assets, which are excluded as the costs incurred were mainly related to the preservation of facilities and subsea infrastructure and do not contribute to production. The costs in 2022 predominately related to the costs incurred to repair the FPSO BUK at the PNLP Assets following the suspension of class in February 2022.

*Restatements explained in Note 50 of the Group's consolidated financial statements.

Adjusted EBITDAX

Adjusted EBITDAX is a non-IFRS measure which does not have a standardised meaning prescribed by IFRS. This non-IFRS measure is included because management uses the measure to analyse cash generation and financial performance of the Group.

Adjusted EBITDAX is defined as profit from continuing activities before income tax, finance costs, interest income, DD&A, other financial gains and non-recurring expenses.

The calculation of adjusted EBITDAX is as follow:

USD'000	2023	2022 Restated*
Revenue	309,200	421,602
Production cost	(232,772)	(250,300)
Administrative staff costs	(30,197)	(29,218)
Other expenses	(22,841)	(22,305)
Share of results of associate	2,640	-
Other income, excluding interest income	14,404	27,152
Other financial gains	-	1,904
Unadjusted EBITDAX	**40,434**	**148,835**
Non-recurring		
Net loss from oil price and foreign exchange derivatives	10,395	-
Non-recurring opex[1]	40,700	20,534
Oil and gas properties written off	3,067	-
Change in provision - Lemang PSC contingent payments	(7,653)	7,333
Insurance claim receipts[2]	-	(17,977)
Fair value loss on contingent considerations	-	1,920

Others[3]	3,704	1,684
	50,213	**13,494**
Adjusted EBITDAX	**90,647**	**162,329**

[1] Non-recurring opex in 2023 includes PenMal Assets' PNLP operational costs and Montara interim tanker storage costs which was temporarily employed as a result of the repair work relating to the storage tanks of the FPSO, diesel fuel consumption by the FPSO during production shutdown and to power the reinjection compressor during production start-up. The Group also incurred charges associated with short lifting a cargo and delivery delays. Non-recurring opex in 2023 also includes repair and maintenance costs in 2023 predominately related to the repair of a gas turbine generator at the PenMal Assets PM329 PSC. The costs in 2022 included one-off major maintenance/well intervention activities, in particular the Montara Skua-11 repair works, gas compressor solar engine change out and storage tank repairs after the Montara production shut-in since mid-August 2022.

[2] Represents proceeds of an insurance claim compensating for the loss of production from the Montara Skua-11 well in 2020. The 2021 insurance claim proceeds related to a well control claim for the Montara Skua-11 well workover.

[3] Includes business development costs, external funding sourcing costs, costs related to the termination of the Maari acquisition and internal reorganisation costs.

*Restatements explained in Note 50 of the Group's consolidated financial statements.

Net cash/debt

Net cash/debt is a non-IFRS measure which does not have a standardised definition prescribed by IFRS. Management uses this measure to analyse the net borrowing position of the Group.

USD'000	2023	2022
Borrowings (principal sum)	157,000	-
Cash and cash equivalents	(153,404)	(123,329)
Net debt/(cash)	**3,596**	**(123,329)**

Net cash/debt is defined as the sum of cash and cash equivalents and restricted cash, less the outstanding principal sum of borrowings.

GLOSSARY

£	British pound sterling
2C	best estimate contingent resource
2P	the sum of proved and probable reserves, reflecting those reserves with 50% probability of quantities actually recovered being equal or greater to the sum of estimated proved plus probable reserves
AAKBNLP	Abu, Abu Kecil, Bubu, North Lukut, and Penara oilfields
AIM	Alternative Investment Market
ARO	Asset retirement obligations
API	American Petroleum Institute gravity
bbl	barrel
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day
DD&A	depletion, depreciation and amortisation
EBITDAX	earnings before interest tax, depreciation, amortisation and exploration
FPSO	floating production storage and offloading
GHG	greenhouse gases
IFRS	International Financial Reporting Standards
LPG	Liquefied petroleum gas
Interim Facility	a US$50 million debt facility closed in February 2023
mscf	thousand standard cubic feet of natural gas
mm	million
mmbbls	million barrels
mmboe	million barrels of oil equivalent

mmcf/d	million standard cubic feet per day
mmscf	million standard cubic feet
MYR	Malaysian Ringgit
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NOPTA	National Offshore Petroleum Titles Administrator
opex	operating expenditures
PETRONAS	Petroliam Nasional Berhad
PITA	Petroleum Income Tax
PRRT	Petroleum Resource Rent Tax
PSC	production sharing contract
RBL	reserves based loan
reserves	hydrocarbon resource that is anticipated to be commercially recovered from known accumulations from a given date forward
resources	being quantities of hydrocarbons which are estimated, on a given date, to be potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable
Saudi CP	Saudi Aramco Contract Price
US$ or USD	United States dollar
VIU	Value in use

The technical information in this announcement has been prepared in accordance with the June 2018 Society of Petroleum Engineers, World Petroleum Congress, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers Petroleum Resource Management System ("PRMS") as the standard for classification and reporting.

A. Shahbaz Sikandar of Jadestone Energy plc, Group Subsurface Manager with a Masters degree in Petroleum Engineering, and who is a member of the Society of Petroleum Engineers and has worked in the energy industry for more than 25 years, has read and approved the technical disclosure in this regulatory announcement.

The information contained within this announcement is considered to be inside information prior to its release, as defined in Article 7 of the Market Abuse Regulation No. 596/2014 which is part of UK law by virtue of the European Union (Withdrawal) Act 2018, and is disclosed in accordance with the Company's obligations under Article 17 of those Regulations.

Consolidated Statement of Profit or Loss and Other Comprehensive Income
for the year ended 31 December 2023

	Notes	2023 USD'000	2022 Restated* USD'000
Consolidated statement of profit or loss			
Continuing operations			
Revenue	4 & 45	309,200	421,602
Production costs	5	(232,772)	(250,300)
Depletion, depreciation and amortisation	6	(76,141)	(61,562)
Administrative staff costs	7	(30,197)	(29,218)
Other expenses	10	(22,841)	(22,305)
Impairment of oil and gas properties	12	(29,681)	(13,534)
Share of results of associate	25	2,640	-
Other income	13	18,855	28,033
Finance costs	14	(41,829)	(11,427)
Other financial gains	15	-	1,904
(Loss)/Profit before tax		**(102,766)**	**63,193**
Income tax credit/(expense)	16	11,492	(53,956)
(Loss)/Profit for the year		**(91,274)**	**9,237**
(Loss)/Profit per ordinary share			
Basic and diluted (US$)	17	(0.18)	0.02
Consolidated statement of other comprehensive income			
(Loss)/Profit for the year		(91,274)	9,237
Other comprehensive (loss)/income			
Items that may be reclassified subsequently to profit or loss:			
Loss on unrealised cash flow hedges	36	(30,509)	-
Hedging loss reclassified to profit or loss	4 & 36	10,322	-

		(20,187)	-
Tax credit relating to components of other comprehensive loss	16	6,056	-
Other comprehensive loss		**(14,131)**	-
Total comprehensive (loss)/income for the year		**(105,405)**	**9,237**

*Certain 2022 comparative information has been restated. Please refer to Note 50.

All comprehensive income is attributable to the equity holders of the parent.

Consolidated Statement of Financial Position as at 31 December 2023

	Notes	31 December 2023 USD'000	31 December 2022 Restated* USD'000	1 January 2022 Restated* USD'000
Assets				
Non-current assets				
Intangible exploration assets	21	79,564	77,928	93,241
Oil and gas properties	22	457,202	433,645	353,592
Plant and equipment	23	10,462	7,318	8,963
Right-of-use assets	24	31,099	8,193	13,852
Investment in associate	25	26,651	-	-
Other receivables and prepayment	29	141,860	90,590	48,500
Deferred tax assets	27	26,774	22,843	23,866
Cash and cash equivalents	30	1,008	676	852
Total non-current assets		**774,620**	**641,193**	**542,866**
Current assets				
Inventories	28	33,654	19,644	23,299
Trade and other receivables	29	124,379	19,635	32,578
Tax recoverable	16	4,085	9,725	9,367
Cash and cash equivalents	30	152,396	122,653	117,013
Total current assets		**314,514**	**171,657**	**182,257**
Total assets		**1,089,134**	**812,850**	**725,123**
Equity and liabilities				
Equity				
Capital and reserves				
Share capital	31	456	339	358
Share premium account	31	51,827	983	201
Merger reserve	33	146,270	146,270	146,270
Share-based payments reserve	34	27,673	26,907	25,936
Capital redemption reserve	35	24	21	-
Hedging reserve	36	(14,131)	-	-
Accumulated losses		(158,349)	(64,991)	(48,942)
Total equity		**53,770**	**109,529**	**123,823**

	Notes	31 December 2023 USD'000	31 December 2022 Restated* USD'000	1 January 2022 Restated* USD'000
Non-current liabilities				
Provisions	37	503,170	510,945	410,697
Borrowings	38	147,313	-	-
Lease liabilities	39	18,746	2,880	4,504
Other payables	41	16,966	-	-
Derivative financial instruments	42	6,708	-	-
Deferred tax liabilities	27	65,829	90,206	77,562
Total non-current liabilities		**758,732**	**604,031**	**492,763**

Total non-current liabilities		758,732	604,031	492,763
Current liabilities				
Borrowings	38	7,260	-	-
Lease liabilities	39	14,118	6,227	11,161
Trade and other payables	41	113,979	73,352	70,107
Derivative financial instruments	42	17,977	-	-
Warrants liability	43 XXXX	3,469	-	-
Provisions	37	108,525	703	930
Tax liabilities		11,304	19,008	26,339
Total current liabilities		**276,632**	**99,290**	**108,537**
Total liabilities		**1,035,364**	**703,321**	**601,300**
TOTAL EQUITY AND LIABILITIES				
Total equity and liabilities		**1,089,134**	**812,850**	**725,123**

*Certain 2022 and 2021 comparative information has been restated and reclassified between line items. Please refer to the affected notes to consolidated financial statements and Note 50

Consolidated Statement of Changes in Equity for the year ended 31 December 2023

	Share capital USD'000	Share premium account USD'000	Merger reserve USD'000	Share-based payments reserve USD'000	Capital redemption reserve USD'000	He res USD
As at 1 January 2022 (Restated)*	358	201	146,270	25,936	-	
Profit for the year, representing total comprehensive income for the year	-	-	-	-	-	
Dividends paid (Note 32)	-	-	-	-	-	
Share-based payments (Note 8)	-	-	-	971	-	
Shares issued (Note 31)	2	782	-	-	-	
Share repurchased (Note 31)	(21)	-	-	-	21	
Total transactions with owners, recognised directly in equity	**(19)**	**782**	-	**971**	**21**	
As at 31 December 2022 (Restated)*	**339**	**983**	**146,270**	**26,907**	**21**	

Share Share-based Capital

	Share capital USD'000	Share premium account USD'000	Merger reserve USD'000	Share-based payments reserve USD'000	Capital redemption reserve USD'000	He res USD
As at 1 January 2023 (Restated)*	339	983	146,270	26,907	21	
Loss for the year	-	-	-	-	-	
Other comprehensive loss for the year	-	-	-	-	-	(14,
Loss for the year, representing total comprehensive income for the year	**-**	**-**	**-**	**-**	**-**	**(14,**
Share-based payments (Note 8)	-	-	-	766	-	
Shares issued (Note 31)	120	52,846	-	-	-	
Transaction costs associated with issuance of shares (Note 31)	-	(2,002)	-	-	-	
Share repurchased (Note 31)	(3)	-	-	-	3	
Total transactions with owners, recognised directly in equity	**117**	**50,844**	**-**	**766**	**3**	
As at 31 December 2023	**456**	**51,827**	**146,270**	**27,673**	**24**	**(14,**

*Certain 2022 and 2021 comparative information has been restated and reclassified between line items. Please refer to the affected notes to consolidated financial statements and Note 50.

Consolidated Statement of Cash Flows for the year ended 31 December 2023

	Notes	2023 USD'000	2022 Restated* USD'000
Operating activities			
(Loss)/Profit before tax		(102,766)	63,193
Adjustments for:			
Depletion, depreciation and amortisation	6	76,141	61,562
Finance costs	14	41,829	11,427
Impairment of oil and gas properties	12	29,681	13,534
Assets written off	10	5,114	212
Share-based payments	7	766	971
Allowance for slow moving inventories	10	655	3,768
(Reversal of)/Change in provision	10 / 13	(7,653)	7,333
Interest income	13	(4,451)	(881)
Share of results of associate	25	(2,640)	-
Unrealised foreign exchange (gain)/loss	10 / 13	(177)	245
Accretion income on Australian tax repayment plan	15	-	(1,904)
Reversal of impairment of amount due from joint arrangement partner	13	-	(912)
Operating cash flows before movements in working capital		**36,499**	**158,548**
(Increase)/Decrease in trade and other receivables		(80,900)	519
Increase in inventories		(15,655)	(1,829)
Increase/(Decrease) in trade and other payables		62,392	(2,871)
Cash generated from operations		**2,336**	**154,367**
Net tax paid		(14,461)	(33,130)
Net cash (used in)/generated from operating activities		**(12,125)**	**121,237**
Investing activities			
Cash paid for acquisition of Sinphuhorm Assets	25	(27,853)	-
Cash received from acquisition of CWLH Assets	19	-	5,750
Cash paid for acquisition of 10% interest of Lemang PSC	20	-	(500)
Payment for oil and gas properties	22	(107,500)	(78,938)
Payment for plant and equipment	23	(516)	(356)
Payment for intangible exploration assets	21	(1,508)	(3,334)
Dividends received from associate	25	3,842	-
Interest received	13	4,451	881

Interest received	13	4,451	881
Net cash used in investing activities		**(129,084)**	**(76,497)**

	Notes	2023 USD'000	2022 Restated* USD'000
Financing activities			
Net proceeds from issuance of shares	31	50,964	784
Shares repurchased	31	(2,084)	(16,070)
Dividends paid	32	-	(9,216)
Total drawdown of borrowings	40	232,000	-
Repayment of borrowings	40	(75,000)	-
Interest on borrowings paid	40	(5,007)	-
Borrowings costs paid	40	(7,595)	-
Commitment fees of borrowings paid	40	(658)	-
Repayment of lease liabilities	40	(14,400)	(13,914)
Interest on lease liabilities paid	40	(2,771)	(769)
Other interest and fees paid		(4,165)	(91)
Net cash generated from/(used in) financing activities		**171,284**	**(39,276)**
Net increase in cash and cash equivalents		**30,075**	**5,464**
Cash and cash equivalents at beginning of the year		123,329	117,865
Cash and cash equivalents at end of the year	30	**153,404**	**123,329**

*Certain 2022 comparative information has been restated and reclassified between line items. Please refer to Note 50.

Notes to the Consolidated Financial Statements for the year ended 31 December 2023

1. CORPORATE INFORMATION

Jadestone Energy plc (the "Company" or "Jadestone") is an oil and gas company incorporated and registered in England and Wales. The Company's registration number is 13152520. The Company is the ultimate parent company of all Jadestone subsidiaries and an associate (the "Group"). These consolidated financial statements have been prepared for the Jadestone Group and reflect the full financial year ended 31 December 2023 in respect of the ultimate parent company in accordance with IFRS (see Note 2).

The Company's shares are traded on AIM under the symbol "JSE".

The financial statements are expressed in United States Dollars ("US$" or "USD").

The Group is engaged in production, development, exploration and appraisal activities in Australia, Malaysia, Vietnam, Indonesia and Thailand. The Group's producing assets are in the Vulcan (Montara) basin, Carnarvon (Stag) basin and Cossack, Wanaea, Lambert, and Hermes oil fields, located in offshore of Western Australia, the East Piatu, East Belumut, West Belumut and Chermingat fields, located in shallow water in offshore Peninsular Malaysia, and in the Sinphuhorm gas

West Belumut and Chermingat fields, located in shallow water in offshore Peninsular Malaysia, and in the Sinphuhorm gas field onshore north-east Thailand.

The Company's head office is located at 3 Anson Road, #13-01 Springleaf Tower, Singapore 079909. The registered office of the Company is 6th Floor, 60 Gracechurch Street, London, EC3V 0HR United Kingdom.

2. ACCOUNTING POLICIES

BASIS OF PREPARATION

The financial statements have been prepared in accordance with UK-adopted International Accounting Standards and International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and in conformity with the requirements of the Companies Act 2006 (the "Act").

The financial statements have been prepared on the historical cost convention basis, except as disclosed in the accounting policies below. Historical cost is generally based on the fair value of the consideration given in exchange for goods and services.

Fair value is the price that would be received from selling an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. In estimating the fair value of an asset or a liability, the Group takes into account the characteristics of the asset or liability which market participants would take into account when pricing the asset or liability at the measurement date. Fair value for measurement and/or disclosure purposes in these consolidated financial statements is determined on such a basis, except for share-based payment transactions that are within the scope of IFRS 2 *Share-based Payment*, leasing transactions that are within the scope of IFRS 16 *Leases*, and measurements that have some similarities to fair value but are not fair value, such as net realisable value in IAS 2 *Inventories*, or value in use in IAS 36 *Impairment of Assets*.

In addition, for financial reporting purposes, fair value adjustments are categorised into level 1, 2 or 3, based on the degree to which the inputs to the fair value adjustments are observable and the significance of the inputs to the fair value measurement in its entirety, which are described as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Group can access at the measurement date;

- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly; and

- Level 3 inputs are unobservable inputs for the asset or liability.

GOING CONCERN

The Directors are required to assess the availability of financial resources to meet the Group's financial liabilities for the foreseeable future, which for the going concern assessment is the period up to 31 December 2025 (the "Review Period").

As at 31 December 2023, the Group had available liquidity of c.US$220.0 million, consisting of cash and cash equivalents (excluding restricted cash) of US$144.2 million, undrawn RBL facility capacity of US$43.0 million and the undrawn committed standby working capital facility of US$31.9 million (the "Working Capital Facility"), from Tyrus Capital Event S.à.r.l ("Tyrus"), the Group's largest shareholder, which expires on 31 December 2024

From the period 1 January 2024 to 31 March 2024, the Group's available unrestricted cash has ranged from US$81.5 million to US$136.6 million, with a balance of US$113.6 million as at 31 March 2024. Other than funding the Group's planned operational and capital expenditures during the first quarter of 2024, the Group also received a payment of US$35.3 million from the previous operator of the PNLP Assets for its share of future well preservation activities and decommissioning costs when it exited two PSCs during 2023, and made a net payment of US$35.7 million for the acquisition of the second 16.67% interest in the CWLH Assets, which comprised of a placement of US$42.0 million into the CWLH abandonment trust fund and a receipt of US$6.3 million from the seller of the interest, reflecting the accumulated economic benefits of the CWLH assets for the period from the effective date of 1 July 2022 to completion.

The March 2024 RBL redetermination has been finalised, setting a borrowing base of US$200.0 million for the six-month period ending 30 September 2024. The available borrowing base is projected at US$200.0 million and US$169.2 million for the six-month periods ending 31 March 2025 and 30 September 2025, respectively.

The Group closely monitors its cash, funding and liquidity position. Near-term cash projections are revised and underlying assumptions reviewed, generally monthly, and longer-term projections are also updated regularly.

The Group's latest cash and liquidity forecasts reflect the outcome of the March 2024 RBL redetermination and the availability of the Working Capital Facility for the period up to 31 December 2024. This represents a 'base case' which includes the Group's current financial position and reflects the expected trading performance of the Group's operations based on the current portfolio of assets, excluding any future business/asset acquisitions.

The Group's forecasts and scenario analyses are, among other factors, based on commodity prices per the current forward curve taking into account the downside risks and the associated impacts. Additionally, the Group's latest liquidity forecasts include the ongoing hedging arrangements entered into as required under the RBL facility.

Various risking scenarios, such as lower oil prices (US$70/bbl flat nominal from July 2024 onwards), unplanned downtime at Montara and CWLH Assets and a potential delay to the Akatara project coming onstream have been modelled. Where liquidity over the Review Period is reduced under these scenarios, the Directors believe that several potential mitigating factors exist in order to increase liquidity, including but not limited to, i) an extension or refinancing of the Group's existing working capital facility, ii) RBL capacity increases from capex add-back or incremental hedging iii) shortening payment terms for liftings from the Group's Australian assets, iv) prepayments for the Group's oil sales and/or v) reducing or deferring the Group's planned capital expenditure.

The Directors have assessed that, based on the cash projections for the Review Period, the Group will have sufficient liquidity in place throughout the Review Period, and also after taking into consideration the various risking scenarios.

Having taken into consideration the above factors, the Directors have reasonable expectation that the Group will continue in operational existence for the Review Period. Accordingly, they adopted the going concern basis in preparing these audited consolidated financial statements.

Adoption of new and revised standards
New and amended IFRS standards that are effective for the current year

In the current year, the Group adopted the following amendments that are effective from the beginning of the year and is relevant to its operations. The adoption of these amendments has not resulted in changes to the Group's accounting policies, except as noted below.

Amendments to IAS 1 and IFRS Practice Statement 2	Disclosure of Accounting Policies
Amendments to IAS 8	Definition of Accounting Estimates
Amendments to IAS 12	International Tax Reform - Pillar Two Model Rules
Amendments to IAS 12	Deferred Tax related to Assets and Liabilities arising from a Single Transaction
Amendments to IFRS 4	Extension of the Temporary Exemption from Applying IFRS 9

The Group's accounting policy has been changed as a result of the adoption of the Amendments to IAS 12 *Deferred Tax related to Assets and Liabilities arising from a Single Transaction*. The amendments introduce a further exception from the initial recognition exemption. Under the amendments, an entity does not apply the initial recognition exemption for transactions that give rise to equal taxable and deductible temporary differences. Depending on the applicable tax law, equal taxable and deductible temporary differences may arise on initial recognition of an asset and liability in a transaction that is not a business combination and affects neither accounting profit nor taxable profit.

Following the amendments to IAS 12, an entity is required to recognise the related deferred tax asset and liability, with the recognition of any deferred tax asset being subject to the recoverability criteria in IAS 12. See Note 50 for further details on the prior year restatements resulting from the adoption of amendments to IAS 12.

New and revised IFRSs in issue but not yet effective

At the date of authorisation of these financial statements, the Group has not applied the following amendments to IFRS standards relevant to the Group that have been issued but are not yet effective:

Amendments to IAS 1	Classification of Liabilities as Current or Non-current
Amendments to IAS 1[1]	Classification of Liabilities as Current or Non-current - Deferral of Effective Date
Amendments to IAS 1[1]	Non-current Liabilities with Covenants
Amendments to IAS 7 and IFRS 7[1]	Supplier Finance Arrangements
Amendments to IAS 21[2]	Lack of exchangeability
Amendments to IFRS 16	Covid-19-Related Rent Concessions beyond 30 June 2021
Amendments to IFRS 16[1]	Lease Liability in a Sale and Leaseback

The Directors of the Group anticipate that the application of these amendments may have an impact on the Group's consolidated financial statements in future periods.

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[1] Effective from 1 January 2024.

[2] To be announced by IASB.

BASIS OF CONSOLIDATION

The consolidated financial statements incorporate the financial statements of the Company and entities controlled by the Company and its subsidiaries made up to 31 December of each year. Control is achieved where the Company:

- Has power over the investee;
- Is exposed, or has rights, to variable returns from its involvement with the investee; and
- Has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control listed above.

Consolidation of a subsidiary begins when the Company obtains control over the subsidiary and ceases when the Company loses control of the subsidiary. Specifically, income and expenses of a subsidiary acquired or disposed of during the year are included in the consolidated statement of profit or loss and other comprehensive income from the date the Company gains control until the date when the Company ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income are attributed to the owners of the Company. Total comprehensive income of subsidiaries is attributed to the owners of the Company.

When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group's accounting policies.

All intragroup assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

BUSINESS COMBINATIONS

Acquisitions of businesses, including joint operations which are assessed to be businesses, are accounted for using the acquisition method. The consideration for each acquisition is measured as the aggregate of the acquisition date fair values of assets given, liabilities incurred by the Company to the former owners of the acquiree, and equity interests issued by the Company in exchange for control of the acquiree. Acquisition-related costs are recognised in profit or loss as incurred.

At the acquisition date, the identifiable assets acquired and the liabilities assumed are recognised at their fair value, except that:

- Deferred tax assets or liabilities, and liabilities or assets related to employee benefit arrangements are recognised and measured in accordance with IAS 12 *Income Taxes* and IAS 19 *Employee Benefits* respectively;

- Liabilities or equity instruments related to share-based payment transactions of the acquiree, or the replacement of an acquiree's share-based payment awards transactions with share-based payment awards transactions of the acquirer, in accordance with the method in IFRS 2 *Share-based Payment* at the acquisition date; and

- Assets, or disposal groups, that are classified as held for sale in accordance with IFRS 5*Non-Current Assets Held for Sale and Discontinued Operations* are measured in accordance with that Standard.

Goodwill is measured as the excess of the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree, and the fair value of the acquirer's previously held equity interest in the acquiree (if any) over the net of the acquisition-date amounts of the identifiable assets acquired and the liabilities assumed. If, after reassessment, the net of the acquisition-date amounts of the identifiable assets acquired and liabilities assumed exceeds the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree and the fair value of the acquirer's previously held interest in the acquiree (if any), the excess is recognised immediately in profit or loss as a bargain purchase gain.

Where applicable, the consideration for the acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its acquisition date fair value. Subsequent changes in such fair values are adjusted against the cost of acquisition where they qualify as measurement period adjustments. Measurement period adjustments are adjustments that arise from additional information obtained during the 'measurement period' (which cannot exceed one year from the acquisition date) about facts and circumstances that existed at the acquisition date. The subsequent accounting for changes in the fair value of the contingent consideration, that do not qualify as measurement period adjustments, depends on how the contingent consideration is classified.

Contingent consideration that is classified as equity is not re-measured at subsequent reporting dates and its subsequent settlement is accounted for within equity. Contingent consideration that is classified as a liability is remeasured at subsequent reporting dates with the corresponding gain or loss being recognised in profit or loss.

If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Group reports provisional amounts for the items for which the accounting is incomplete. Those provisional amounts are adjusted during the measurement period (see below), or additional assets or liabilities are recognised, to reflect new information obtained about facts and circumstances that existed as of the acquisition date that, if known, would have affected the amounts recognised as at that date.

The measurement period is the period from the date of acquisition to the date the Group obtains complete information about facts and circumstances that existed as at the acquisition date and is subject to a maximum of one year from acquisition date.

Where an interest in a production sharing contract ("PSC") is acquired by way of a corporate acquisition, the interest in the PSC is treated as an asset purchase unless the acquisition of the corporate vehicle meets the definition of a business and the requirements to be treated as a business combination.

ACCOUNTING FOR TRANSACTION THAT IS NOT A BUSINESS COMBINATION

When a transaction or other event does not meet the definition of a business combination due to the asset or group of assets not meeting the definition of a business, it is termed an 'asset acquisition'. In such circumstances, the acquirer:

- Identifies and recognises the individual identifiable assets acquired (including those assets that meet the definition of, and recognition criteria for, intangible assets in [IAS 38]) and liabilities assumed; and

- Allocates the cost of acquiring the group of assets and liabilities to the individual identifiable assets and liabilities on the basis of their relative fair values at the date of purchase.

Such a transaction or event does not give rise to goodwill or a gain on a bargain purchase.

Transaction costs in an asset acquisition are generally capitalised as part of the cost of the assets acquired in accordance with applicable standards.

FOREIGN CURRENCY TRANSACTIONS

The Group's consolidated financial statements are presented in USD, which is the parent's functional currency and presentation currency. The functional currencies of subsidiaries are determined based on the economic environment in which they operate.

In preparing the financial statements of each individual Group entity, transactions in currencies other than the entity's functional currency are recorded at the rates of exchange prevailing on the dates of the transactions. At the end of each reporting period, monetary items denominated in foreign currencies are retranslated at the rates prevailing at the end of the reporting period. Non-monetary items carried at fair value that are denominated in foreign currencies are retranslated at the rates prevailing on the date when the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated.

Exchange differences arising on the settlement of monetary items, and on retranslation of monetary items, are included in profit or loss for the period.

Exchange differences arising on the retranslation of non-monetary items carried at fair value are included in profit or loss for the period, except for differences arising on the retranslation of non-monetary items in respect of which gains or losses are recognised in other comprehensive income. For such non-monetary items, any exchange component of that gain or loss is also recognised in other comprehensive income. There is no foreign currency translation reserve created at the Group level as the functional currencies of all subsidiaries are denominated in USD.

JOINT OPERATIONS

A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

When a Group entity undertakes its activities under joint operations, the Group as a joint operator recognises in relation to its interest in a joint operation:

- Its assets, including its share of any assets held jointly;
- Its liabilities, including its share of any liabilities incurred jointly;
- Its revenue from the sale of its share of the output arising from the joint operation; and
- Its expenses, including its share of any expenses incurred jointly.

The Group accounts for the assets, liabilities, revenue and expenses relating to its interest in a joint operation in accordance with the IFRS standards applicable to the particular assets, liabilities, revenues and expenses.

When a Group entity transacts with a joint operation in which a Group entity is a joint operator (such as a sale or contribution of assets), the Group is considered to be conducting the transaction with the other parties to the joint operation, and gains and losses resulting from the transactions are recognised in the Group's consolidated financial statements only to the extent of other parties' interests in the joint operation.

When a Group entity transacts with a joint operation in which a Group entity is a joint operator (such as a purchase of assets), the Group does not recognise its share of the gains and losses until it resells those assets to a third party.

Changes to the Group's interest in a PSC usually require the approval of the appropriate regulatory authority. A change in interest is recognised when:

- Approval is considered highly likely; and
- All affected parties are effectively operating under the revised arrangement.

Where this is not the case, no change in interest is recognised and any funds received or paid are included in the statement of financial position as contractual deposits.

INVESMENT IN ASSOCIATES AND JOINT VENTURES

An associate is an entity over which the group has significant influence and that is neither a subsidiary nor an interest in a joint venture. Significant influence is the power to participate in the financial and operating policy decisions of the investee but is not control or joint control over those policies.

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the joint arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

The results and assets and liabilities of associates are incorporated in these financial statements using the equity method of accounting.

Under the equity method, an investment in an associate or a joint venture is recognised initially in the consolidated statement of financial position at cost and adjusted thereafter to recognise the Group's share of the profit or loss and other comprehensive income of the associate. When the Group's share of losses of an associate exceeds the Group's interest in that associate (which includes any long-term interests that, in substance, form part of the group's net investment in the associate), the Group discontinues recognising its share of further losses. Additional losses are recognised only to the extent that the Group has incurred legal or constructive obligations or made payments on behalf of the associate.

An investment in an associate is accounted for using the equity method from the date on which the investee becomes an associate. On acquisition of the investment in an associate, any excess of the cost of the investment over the Group's share of the net fair value of the identifiable assets and liabilities of the investee is recognised as goodwill, which is included within the carrying amount of the investment. Any excess of the Group's share of the net fair value of the identifiable assets and liabilities over the cost of the investment, after reassessment, is recognised immediately in profit or loss in the period in which the investment is acquired.

If there is objective evidence that the Group's net investment in an associate is impaired, the requirements of IAS 36 are applied to determine whether it is necessary to recognise any impairment loss with respect to the Group's investment. When necessary, the entire carrying amount of the investment (including goodwill) is tested for impairment in accordance with IAS 36 as a single asset by comparing its recoverable amount (higher of value in use and fair value less costs of disposal) with its carrying amount. Any impairment loss recognised is not allocated to any asset, including goodwill that forms part of the carrying amount of the investment. Any reversal of that impairment loss is recognised in accordance with IAS 36 to the extent that the recoverable amount of the investment subsequently increases.

EXPLORATION AND EVALUATION COSTS

The costs of exploring for and evaluating oil and gas properties, including the costs of acquiring rights to explore, geological and geophysical studies, exploratory drilling and directly related overheads such as directly attributable employee remuneration, materials, fuel used, rig costs and payments made to contractors are capitalised and classified as intangible exploration assets ("E&E assets").

If no potentially commercial hydrocarbons are discovered, the E&E assets are written off through profit or loss as a dry hole. If extractable hydrocarbons are found and, subject to further appraisal activity (e.g., the drilling of additional wells), it is probable that they can be commercially developed, the costs continue to be carried as intangible exploration costs, while sufficient/continued progress is made in assessing the commerciality of the hydrocarbons.

Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalised as E&E assets.

All such capitalised costs are subject to technical, commercial and management review, as well as review for indicators of impairment at the end of each reporting period. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When such intent no longer exists, or if there is a change in circumstances signifying an adverse change in initial judgment, the costs are written off.

When commercial reserves of hydrocarbons are determined and development is approved by management, the relevant expenditure is transferred to oil and gas properties. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. The determination of proved or probable reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Costs related to geological and geophysical studies that relate to blocks that have not yet been acquired, and costs related to blocks for which no commercially viable hydrocarbons are expected, are taken direct to the profit or loss and have been disclosed as exploration expenses.

OIL AND GAS PROPERTIES

Producing assets

The Group recognises oil and gas properties at cost less accumulated depletion, depreciation and impairment losses. Directly attributable costs incurred for the drilling of development wells and for the construction of production facilities are capitalised, together with the discounted value of estimated future costs of decommissioning obligations. Workover expenses are recognised in profit or loss in the period in which they are incurred, unless it generates additional reserves or prolongs the economic life of the well, in which case it is capitalised. When components of oil and gas properties are replaced, disposed of, or no longer in use, they are derecognised.

Depletion and amortisation expense

Depletion of oil and gas properties is calculated using the units of production method for an asset or group of assets, from the date in which they are available for use. The costs of those assets are depleted based on proved and probable reserves.

Costs subject to depletion include expenditures to date, together with approved estimated future expenditure to be incurred in developing proved and probable reserves. Costs of major development projects are excluded from the costs subject to depletion until they are available for use.

The impact of changes in estimated reserves is dealt with prospectively by depleting the remaining carrying value of the asset over the remaining expected future production. If reserves estimates are revised downwards, earnings could be affected by higher depletion expense, or an immediate write-down of the property's carrying value.

Depletion amount calculated based on production during the year is adjusted based on the net movement of crude inventories at year end against beginning of the year, i.e., depletion cost for crudes produced but not lifted are capitalised as part of cost of inventories and recognised as depletion expense when lifting occurs.

Asset restoration obligations

The Group estimates the future removal and restoration costs of oil and gas production facilities, wells, pipelines and related assets at the time of installation or acquisition of the assets, and based on prevailing legal requirements and industry practice. In most instances, the removal of these assets will occur many years in the future. The estimates of future removal costs are made considering relevant legislation and industry practice and require management to make judgments regarding the removal date, the extent of restoration activities required, and future removal technologies.

Site restoration costs are capitalised within the cost of the associated assets, and the provision is stated in the statement of financial position at its total estimated present value. These costs are based on judgements and assumptions regarding removal dates, technologies, and industry practice. This estimate is evaluated on a periodic basis and any adjustment to the estimate is applied prospectively. Changes in the estimated liability resulting from revisions to estimated timing, amount of cash flows, or changes in the discount rate are recognised as a change in the asset restoration liability and related capitalised asset restoration cost within oil and gas properties.

The Malaysian and Indonesian regulators require upstream oil and gas companies to contribute to an abandonment cess fund, including making periodic cess payments, throughout the production life of the oil or gas field. The Malaysian cess payment amount is assessed based on the estimated future decommissioning expenditures on oil and gas facilities, excluding wells. The Indonesian cess payment amount is assessed based on the estimated future decommissioning expenditures of all facilities. For operated licences, the cess payment paid is classified as non-current receivables as the cess payment paid is reclaimable by the Group in the future following the commencement of decommissioning activities. For non-operated licences, the cess payment paid reduces the asset restoration liability.

An abandonment trust fund was set up as part of the acquisition of the CWLH Assets to ensure there are sufficient funds available for decommissioning activities at the end of field life. The payment paid into the trust fund is classified as non-current receivables as the amount is reclaimable by the Group in the future following the commencement of decommissioning activities.

The change in the net present value of future obligations, due to the passage of time, is expensed as an accretion expense within financing charges. Actual restoration obligations settled during the period reduce the decommissioning liability.

Capitalised asset restoration costs are depleted using the units of production method (see above accounting policy).

BORROWING COSTS

Borrowing costs are allocated to periods over the term of the related debt, at a constant rate on the carrying amount. Borrowings, as shown on the consolidated statement of financial position, are net of arrangement fees and issue costs, and the borrowing costs are amortised through to the statement of profit or loss and other comprehensive income as finance costs over the term of the debt.

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale.

All other borrowing costs are recognised in the profit or loss in the period in which they are incurred.

Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalisation. All other borrowing costs are recognised in the statement of profit or loss in the period in which they are incurred.

PLANT AND EQUIPMENT

Plant and equipment is stated at cost less accumulated depreciation and any recognised impairment loss.

Depreciation is charged so as to write off the cost of assets evenly over their estimated useful lives, on the following:

- Computer equipment: 3 years; and

- Fixtures and equipment: 3 years.

The estimated useful lives, residual values and depreciation method are reviewed at each year end, with the effect of any changes in estimate accounted for on a prospective basis.

Materials and spares which are not expected to be consumed within the next twelve months from the year end are classified as plant and equipment.

Right-of-use assets are depreciated over the shorter period of the lease term and the useful life of the underlying asset. If the ownership of the underlying asset in a lease is transferred, or the cost of the right-of-use asset reflects that the Group expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset.

An item of plant and equipment is derecognised upon disposal or when no future economic benefits are expected to arise from the continued use of asset. Any gain or loss arising on the disposal or retirement of an item of plant and equipment is determined as the difference between the sales proceeds and the carrying amount of the asset and is recognised in profit or loss.

IMPAIRMENT OF OIL AND GAS PROPERTIES, PLANT AND EQUIPMENT, RIGHT-OF-USE ASSETS AND INTANGIBLE EXPLORATION ASSETS

At the end of each reporting period, the Group reviews the carrying amounts of its oil and gas properties, plant and equipment, right-of-use assets and intangible assets, excluding goodwill, to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). The impairment is determined on each individual cash-generating unit basis (i.e., individual oil or gas field or individual PSC). Where there is common infrastructure that is not possible to measure the cash flows separately for each oil or gas field or PSC, then the impairment is determined based on the aggregate of the relevant oil or gas fields or the combination of two or more PSCs. When a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual cash-generating units, or otherwise they are allocated to the smallest group of cash-generating units for which a reasonable and consistent allocation basis can be identified.

Recoverable amount is the higher of fair value less costs of disposal ("FVLCOD") and value in use ("VIU"). In assessing VIU, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which estimates of future cash flows have not been adjusted. FVLCOD will be assessed on a discounted cash flow basis where there is no readily available market price for the asset or where there are no recent market transactions.

If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (or cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognised immediately in profit or loss.

Where an impairment loss subsequently reverses, the carrying amount of the asset (or cash-generating unit) is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset (or cash-generating unit) in prior years. A reversal of an impairment loss is recognised immediately in profit or loss.

INVENTORIES

Inventories are valued at the lower of cost and net realisable value. Cost is determined as follows:

- Petroleum products, comprising primarily of extracted crude oil stored in tanks, pipeline systems and aboard vessels, and natural gas, are valued using weighted average costing, inclusive of depletion expense; and

- Materials, which include drilling and maintenance stocks, are valued at the weighted average cost of acquisition.

Net realisable value represents the estimated selling price in the ordinary course of business less the estimated costs of completion and the estimated costs necessary to make the sale. The Group uses its judgement to determine which costs are necessary to make the sale considering its specific facts and circumstances, including the nature of the inventories. If the carrying value exceeds net realisable value, a write-down is recognised. The write-down may be reversed in a subsequent period if the inventory is still on hand, but the circumstances which caused the write-down no longer to exist.

Provision for slow moving materials and spares are recognised in the "other expenses" (Note 10) line item in profit or loss as they are non-trade in nature.

FINANCIAL INSTRUMENTS

Financial assets and financial liabilities are recognised in the Group's consolidated statement of financial position when the Group becomes a party to the contractual provisions of the instrument.

Financial assets and financial liabilities are initially measured at fair value. Transaction costs that are directly attributable to the acquisition or issue of the financial assets and financial liabilities (other than financial assets and financial liabilities measured at fair value through the profit or loss) are added to or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition.

Transaction costs directly attributable to the acquisition of financial assets or financial liabilities measured at fair value through profit or loss are recognised immediately in profit or loss.

Financial assets

All financial assets are recognised and derecognised on a trade date basis, where the purchases or sales of financial assets is under a contract whose terms require delivery of assets within the time frame established by the market concerned.

All recognised financial assets are measured subsequently in their entirety, at either amortised cost or fair value, depending on the classification of the financial assets.

Classification of financial assets

Debt instruments that meet the following conditions are measured subsequently at amortised cost:

- The financial asset is held within a business model whose objective is to hold financial assets in order to collect contractual cash flows; and

- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Debt instruments that meet the following conditions are subsequently measured at fair value through other comprehensive income ("FVTOCI"):

- The financial asset is held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets; and

- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

By default, all other financial assets are subsequently measured at fair value through profit or loss ("FVTPL").

Amortised cost and effective interest method

The effective interest method is a method of calculating the amortised cost of a financial asset and of allocating interest income over the relevant period.

For financial assets, the effective interest rate is the rate that exactly discounts estimated future cash receipts (including all fees paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) excluding expected credit losses, through the expected life of the financial asset, or, where appropriate, a shorter period, to the gross carrying amount of the financial instrument on initial recognition.

The amortised cost of a financial asset is the amount at which the financial asset is measured at initial recognition minus the principal repayments, plus the cumulative amortisation using the effective interest method of any difference between the principal repayments, plus the cumulative amortisation using the effective interest method of any difference between that initial amount and the maturity amount, adjusted for any loss allowance. The gross carrying amount of a financial asset is the amortised cost of a financial asset before adjusting for any loss allowance.

Interest income is recognised using the effective interest method for financial assets measured subsequently at amortised cost and at fair value through other comprehensive income. For financial assets other than purchased or originated credit impaired financial assets, interest income is calculated by applying the effective interest rate to the gross carrying amount of a financial asset, except for financial assets that have subsequently become credit impaired. For financial assets that have subsequently become credit impaired, interest income is recognised by applying the effective interest rate to the amortised cost of the financial asset. If, in subsequent reporting periods, the credit risk on the credit impaired financial instrument improves so that the financial asset is no longer credit impaired, interest income is recognised by applying the effective interest rate to the gross carrying amount of the financial asset.

Interest income is recognised in profit or loss and is included in "other income" (Note 13) line item.

Impairment of financial assets

The Group's financial assets that are subject to the expected credit loss model comprise trade and other receivables. While cash and bank balances are also subject to the impairment requirements of IFRS 9*Financial Instruments*, the expected credit loss allowances are not expected to be significant due to the banks having external credit ratings of 'investment grade' in accordance with the globally understood definition.

The Group's trade and other receivables are primarily with counterparties to oil and gas sales, joint arrangement partners and non-trade related parties.

The concentration of credit risk relates to the Group's single customer with respect to oil sales in Australia, and a different single customer for oil and gas sales in Malaysia. Both customers havean A2 credit rating (Moody's). All trade receivables are generally settled 30 days after the sale date. In the event that an invoice is issued on a provisional basis then the final reconciliation is paid within three days of the issuance of the final invoice, largely mitigating any credit risk.

The Group recognises lifetime expected credit loss ("ECL") for trade receivables. The expected credit losses on these financial assets are estimated based on days past due, applying expected non-recoveries for each group of receivables.

The Group measures the loss allowance for other receivables and amounts due from joint arrangement partners at an amount equal to 12 months ECL, as there is no significant increase in credit risk since initial recognition.

Significant increase in credit risk

In assessing whether the credit risk on a financial instrument has increased significantly since initial recognition, the Group compares the risk of a default occurring on the financial instrument as at the reporting date with the risk of a default occurring on the financial instrument as at the date of initial recognition. In making this assessment, the Group considers both quantitative and qualitative information that is reasonable and supportable, including historical experience and forward looking information that is available without undue cost or effort. Forward looking information considered includes the future prospects of the industries in which the Group's debtors operate, based on consideration of various external sources of actual and forecast economic information plus environment impacts that relate to the Group's core operations.

In particular, the following information is taken into account when assessing whether credit risk has increased significantly since initial recognition:

- An actual or expected significant deterioration in the financial instrument's external (if available), or internal credit rating;

- Significant deterioration in external market indicators of credit risk for a particular financial instrument, e.g., a significant increase in the credit spread, the credit default swap prices for the debtor, or the length of time or the extent to which the fair value of a financial asset has been less than its amortised cost;

- Existing or forecast adverse changes in business, financial or economic conditions that are expected to cause a significant decrease in the debtor's ability to meet its debt obligations;

- An actual or expected significant deterioration in the operating results of the debtor;

- Significant increases in credit risk on other financial instruments of the same debtor; and

- An actual or expected significant adverse change in the regulatory, economic, or technological environment of the debtor that results in a significant decrease in the debtor's ability to meet its debt obligations.

Despite the foregoing, the Group assumes that the credit risk on a financial instrument has not increased significantly since initial recognition if the financial instrument is determined to have low credit risk at the reporting date. A financial instrument is determined to have low credit risk if i) the financial instrument has a low risk of default, ii) the borrower has a strong capacity to meet its contractual cash flow obligations in the near term and iii) adverse changes in economic and business conditions in the longer term may, but will not necessarily, reduce the ability of the borrower to fulfil its contractual cash flow obligations.

The Group regularly monitors the effectiveness of the criteria used to identify whether there has been a significant increase in credit risk and revises them, as appropriate, to ensure that the criteria are capable of identifying a significant increase in credit risk before the amount becomes past due.

Definition of default

The Group considers the following as constituting an event of default, for internal credit risk management purposes, as historical experience indicates that receivables that meet either of the following criteria are generally not recoverable:

- When there is a breach of financial covenants by the counterparty; or
- Information developed internally or obtained from external sources indicates that the debtor is unlikely to pay its creditors, including the Group, in full (without taking into account any collateral held by the Group).

Credit-impaired financial assets

A financial asset is credit-impaired when one or more events that have a detrimental impact on the estimated future cash flows of that financial asset have occurred. Evidence that a financial asset is credit-impaired includes observable data about the following events:

- Significant financial difficulty of the issuer or the borrower;
- A breach of contract, such as a default or past due event;
- The lender(s) of the borrower, for economic or contractual reasons relating to the borrower's financial difficulty, having granted to the borrower a concession(s) that the lender(s) would not otherwise consider;
- It is becoming probable that the borrower will enter bankruptcy or other financial reorganisation; or
- The disappearance of an active market for that financial asset because of financial difficulties.

Write-off policy

The Group writes off a financial asset when there is information indicating that the counterparty is in severe financial difficulty and there is no realistic prospect of recovery, e.g., when the counterparty has been placed under liquidation or has entered into bankruptcy proceedings, or in the case of trade receivables, when the amounts are over one year past due, whichever occurs sooner. Financial assets written off may still be subject to enforcement activities under the Group's recovery procedures, taking into account legal advice where appropriate. Any recoveries made are recognised in profit or loss.

Measurement and recognition of expected credit losses

The measurement of ECL is a function of the probability of default, loss given default (i.e., the magnitude of the loss if there is a default), and the exposure at default. The assessment of the probability of default, and loss given default, is based on historical data adjusted by forward looking information as described above.

As for the exposure at default, for financial assets, this is represented by the assets' gross carrying amount at the reporting date, together with any additional amounts expected to be drawn down in the future by the default date determined based on historical trend, the Group's understanding of the specific future financing needs of the debtors, and other relevant forward looking information.

For financial assets, the expected credit loss is estimated as the difference between all contractual cash flows that are due to the Group in accordance with the contract, and all the cash flows that the Group expects to receive, discounted at the original effective interest rate.

If the Group has measured the loss allowance for a financial instrument at an amount equal to lifetime ECL in the previous reporting period, but determines at the current reporting date that the conditions for lifetime ECL are no longer met, the Group measures the loss allowance at an amount equal to 12 month ECL at the current reporting date, except for assets for which the simplified approach was used.

Derecognition of financial assets

The Group derecognises a financial asset only when the contractual rights to the cash flows from the asset expire, or when it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another entity. If the Group neither transfers nor retains substantially all the risks and rewards of ownership, and continues to control the transferred asset, the Group recognises its retained interest in the asset and an associated liability for amounts it may have to pay. If the Group retains substantially all of the risks and rewards of ownership of a transferred financial asset, the Group continues to recognise the financial asset and also recognises a collaterialised borrowing for the proceeds received.

On derecognition of a financial asset measured at amortised cost, the difference between the asset's carrying amount and the sum of the consideration received and receivables, is recognised in the profit or loss.

Financial liabilities

All financial liabilities are measured subsequently at amortised cost, using the effective interest method or at FVTPL.

However, financial liabilities that arise when a transfer of a financial asset does not qualify for derecognition, or when the continuing involvement approach applies, are measured in accordance with the specific accounting policies set out below.

Financial liabilities at FVTPL

Financial liabilities are classified as at FVTPL when the financial liability is (i) contingent consideration of an acquirer in a business combination, (ii) held for trading, or (iii) designated as at FVTPL.

A financial liability other than a contingent consideration of an acquirer in a business combination may be designated as at

A financial liability other than a contingent consideration of an acquirer in a business combination may be designated as at FVTPL upon initial recognition if:

- Such designation eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise; or

- The financial liability forms part of a group of financial assets or financial liabilities or both, which is managed and its performance is evaluated on a fair value basis, in accordance with the Group's documented risk management or investment strategy, and information about the grouping is provided internally on that basis; or

- It forms part of a contract containing one or more embedded derivatives, and IFRS 9 permits the entire combined contract to be designated as at FVTPL.

Financial liabilities classified as at FVTPL are measured at fair value, with any gains or losses arising on changes in fair value recognised in profit or loss to the extent that they are not part of a designated hedging relationship (see hedge accounting policy). The net gain or loss recognised in profit or loss incorporates any interest paid on the financial liability and is included in either "other financial gains" (Note 15) or "finance costs" (Note 14) line item in profit or loss.

Financial liabilities measured subsequently at amortised cost

Other financial liabilities are measured subsequently at amortised cost, using the effective interest method.

The effective interest method is a method of calculating the amortised cost of a financial liability and of allocating interest expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash payments (including all fees paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) through the expected life of the financial liability, or (where appropriate) a shorter period, to the amortised cost of a financial liability.

Derecognition of financial liabilities

The Group derecognises financial liabilities when, and only when, the Group's obligations are discharged, cancelled or they expire. The difference between the carrying amount of the financial liability derecognised, and the consideration paid and payable, is recognised in profit or loss.

Equity instruments

Ordinary shares issued by the Company are classified as equity and recorded at the par value in the share capital account and the fair value of the proceeds received recorded in the share premium account.

Derivative financial instruments

The Group enters into a variety of derivative financial instruments to manage its exposure to commodity price and foreign exchange risks.

Derivatives are initially recognised at fair value on the date the contract is entered into, and are subsequently remeasured to fair value as at each reporting date. The resulting gain or loss is recognised in profit or loss immediately unless the derivative is designated and effective as a hedging instrument, in which case the timing of the recognition in profit or loss depends on the nature of the hedge relationship.

A derivative with a positive fair value is recognised as a financial asset whereas a derivative with a negative fair value is recognised as a financial liability. Derivatives are not offset in the financial statements unless the Group has both a legally enforceable right and intention to offset. A derivative is presented as a non-current asset or a non-current liability if the remaining maturity of the instrument is more than 12 months and it is not due to be realised or settled within 12 months. Other derivatives are presented as current assets or current liabilities.

Hedge accounting

All hedges are classified as cash flow hedges, which hedges exposure to the variability in cash flows that is either attributable to a particular risk associated with a recognised asset or liability, or a component of a recognised asset or liability, or a highly probable forecasted transaction.

At the inception of the hedge relationship, the Group documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. Furthermore, at the inception of the hedge and on an ongoing basis, the Group documents whether the hedging instrument is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- there is an economic relationship between the hedged item and the hedging instrument;

- the effect of credit risk does not dominate the value changes that result from that economic relationship; and

- the hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Group actually hedges and the quantity of the hedging instrument that the Group actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Group adjusts the hedge ratio of the hedging relationship (i.e. rebalances the hedge), so that it meets the qualifying criteria again.

The Group designates the full change in the fair value of a forward contract (i.e. including the forward elements) as the hedging instrument, for all of its hedging relationships involving forward contracts. The Group designates only the intrinsic value of option contracts as a hedged item, i.e. excluding the time value of the option. The changes in the fair value of the aligned time value of the option are recognised in other comprehensive income and accumulated in the cost of hedging reserve. If the hedged item is transaction related, the time value is reclassified to profit or loss when the hedged item affects reserve. If the hedged item is transaction related, the time value is reclassified to profit or loss when the hedged item affects profit or loss. If the hedged item is time period related, then the amount accumulated in the cost of hedging reserve is reclassified to profit or loss on a rational basis; the Group applies straight line amortisation. Those reclassified amounts are recognised in profit or loss in the same line as the hedged item. If the hedged item is a non financial item, then the amount accumulated in the cost of hedging reserve is removed directly from equity and included in the initial carrying amount of the recognised non financial item. Furthermore, if the Group expects that some or all of the loss accumulated in cost of hedging reserve will not be recovered in the future, that amount is immediately reclassified to profit or loss.

Note 42 sets out details of the fair values of the derivative instruments used for hedging purposes.

Movements in the hedging reserve in equity are detailed in Note 36.

Cash flow hedges

The effective portion of changes in the fair value of derivatives and other qualifying hedging instruments that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated under the heading of cash flow hedging reserve, limited to the cumulative change in fair value of the hedged item from inception of the hedge. The gain or loss relating to the ineffective portion is recognised immediately in profit or loss in either "other financial gains" (Note 15) or "finance costs"
(Note 14) line item.

Amounts previously recognised in other comprehensive income and accumulated in equity are reclassified to profit or loss in the periods when the hedged item affects profit or loss, in the same line as the recognised hedged item. If the Group expects that some or all of the loss accumulated in the cash flow hedging reserve will not be recovered in the future, that amount is immediately reclassified to profit or loss.

The Group discontinues hedge accounting only when the hedging relationship (or a part thereof) ceases to meet the qualifying criteria (after rebalancing, if applicable). This includes instances when the hedging instrument expires or is sold, terminated or exercised. The discontinuation is accounted for prospectively. Any gain or loss recognised in other comprehensive income and accumulated in cash flow hedge reserve, at that time, remains in equity and is reclassified to profit or loss when the forecast transaction occurs. When a forecast transaction is no longer expected to occur, the gain or loss accumulated in cash flow hedge reserve is reclassified immediately to profit or loss.

FAIR VALUE ESTIMATION OF FINANCIAL ASSETS AND LIABILITIES

The fair value of current financial assets and liabilities carried at amortised cost, approximate their carrying amounts, as the effect of discounting is immaterial.

SHARE-BASED PAYMENTS

Share-based incentive arrangements are provided to employees, allowing them to acquire shares of the Company.

The fair value of equity-settled options granted is recognised as an employee expense, with a corresponding increase in equity.

Equity-settled share options are valued at the date of grant using the Black-Scholes pricing model, and are charged to operating costs over the vesting period of the award. The charge is modified to take account of options granted to employees who leave the Group during the vesting period and forfeit their rights to the share options. In the case of market-related performance conditions, the Group revises its estimates of the number of equity instruments expected to vest at the end of the reporting period. The impact of the revision of the original estimates, if any, is recognised in profit or loss such that the cumulative expense reflects the revised estimate, with a corresponding adjustment to the share options reserve.

Equity-settled share-based payment transactions with parties other than employees are measured at the fair value of goods or services received, except where that fair value cannot be estimated reliably, in which case they are measured at the fair value of the equity instruments granted, measured at the date at which the entity obtains the goods or the counterparty renders the service.

LEASES

The Group as lessee

The Group assesses whether a contract is or contains a lease, at inception of the contract. The Group recognises a right-of-use asset and a corresponding lease liability with respect to all lease arrangements in which it is the lessee, except for short-term leases (defined as leases with a lease term of 12 months or less) and leases of low value assets (such as personal computers, small items of office furniture and telephones). For these leases, the Group recognises the lease payments as an operating expense on a straight-line basis over the term of the lease, unless another systematic basis is more representative of the time pattern in which economic benefits from the leased assets are consumed.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate implicit in the lease. If this rate cannot be readily determined, the lessee uses its estimated incremental borrowing rate.

Lease payments included in the measurement of the lease liability comprise fixed lease payments (including in substance fixed payments).

The lease liability is presented as a separate line in the consolidated statement of financial position.

The lease liability is subsequently measured by increasing the carrying amount to reflect interest on the lease liability (using the effective interest method), and by reducing the carrying amount to reflect the lease payments made.

The Group remeasures the lease liability (and makes a corresponding adjustment to the related right-of-use asset) whenever:

- The lease term has changed or there is a significant event or change in circumstances resulting in a change in the assessment of exercise of a purchase option, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate;

- The lease payments change due to changes in an index or rate or a change in expected payment under a guaranteed residual value, in which case the lease liability is remeasured by discounting the revised lease payments using an unchanged discount rate (unless the lease payments change is due to a change in a floating interest rate, in which case a revised discount rate is used); or

- A lease contract is modified and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured based on the lease term of the modified lease by discounting the revised lease payments using a revised discount rate at the effective date of the modification.

During the year, the Group did not make any such adjustments.

The right-of-use assets comprise the initial measurement of the corresponding lease liability, lease payments made at or before the commencement day, less any lease incentives received and any initial direct costs. They are subsequently measured at cost less accumulated depreciation and impairment losses.

Whenever the Group incurs an obligation for costs to dismantle and remove a leased asset, restore the site on which it is located, or restore the underlying asset to the condition required by the terms and conditions of the lease, a provision is recognised and measured under IAS 37. To the extent that the costs relate to a right-of-use asset, the costs are included in the related right-of-use asset, unless those costs are incurred to produce inventories.

Right-of-use assets are depreciated over the shorter period of the lease term and the useful life of the underlying asset. If a lease transfers ownership of the underlying asset, or the cost of the right-of-use asset reflects that the Group expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. The depreciation starts at the commencement date of the lease.

Right-of-use assets are presented as a separate line in the consolidated statement of financial position.

The Group applies IAS 36 to determine whether a right-of-use asset is impaired and accounts for any identified impairment loss as described in the "Impairment of Assets" policy.

As a practical expedient, IFRS 16 permits a lessee not to separate non-lease components, and instead account for any lease and associated non-lease components as a single arrangement. The Group has not used this practical expedient. For contracts that contain a lease component and one or more additional lease or non-lease components, the Group allocates the consideration in the contract to each lease component on the basis of the relative stand-alone price of the lease component and the aggregate standalone price of the non-lease components.

PROVISIONS

Provisions are recognised when the Group has a present obligation, legal or constructive, as a result of a past event, and it is probable that the Group will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation.

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows, and where the effect of the time value of money is material. The provisions held by the Group are asset restoration obligations, contingent payments, employee benefits and incentive scheme, as set out in Note 37.

RETIREMENT BENEFIT OBLIGATIONS

Payments to defined contribution retirement benefit plans are charged as an expense as and when employees have tendered the services entitling them to the contributions. Payments made to state managed retirement benefit schemes, such as Malaysia's Employees Provident Fund, are dealt with as payments to defined contribution plans where the Group's obligations under the plans are equivalent to those arising in a defined contribution retirement benefit plan. The Group does not have any defined benefit plans.

REVENUE

Revenue from contracts with customers is recognised in the profit or loss when performance obligations are considered met, which is when control of the hydrocarbons are transferred to the customer.

Revenue from the production of oil and gas, in which the Group has an interest with other producers, is recognised based on the Group's working interest and the terms of the relevant production sharing contracts.

Liquids production revenue is recognised when the Group gives up control of the unit of production at the delivery point agreed under the terms of the sale contract. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism. The amount of production revenue recognised is based on the agreed transaction price and volumes delivered. In line with the aforementioned, revenue is recognised at a point in time when deliveries of the liquids are transferred to customers.

Gas production revenue is meter measured based on the hydrocarbon volumes delivered. The volumes delivered over a calendar month are invoiced based on monthly meter readings. The price is either fixed (gas) or linked to an agreed benchmark (high sulphur fuel oil) in advance. This methodology is considered appropriate as it is normal business practice under such arrangements. In line with the aforementioned, revenue is recognised at a point in time when deliveries of the gas are transferred to the customer.

A receivable is recognised once transfer has occurred, as this represents the point in time at which the right to consideration becomes unconditional, and only the passage of time is required before the payment is due.

Under/Overlift

Offtake arrangements for oil and gas produced in certain of the Group's jointly owned operations may result in the Group not receiving and selling its precise share of the overall production in a period. The resulting imbalance between the Group's cumulative entitlement and share of cumulative production less stock gives rise to an underlift or overlift.

Entitlement imbalances in under/overlift positions and the movements in inventory are included in production costs (Note 5). An overlift liability is measured on the basis of the cost of production and represents a provision for production costs attributable to the volumes sold in excess of entitlement. The underlift asset is measured at the lower of cost and net realisable value, consistent with IAS 2, to represent a right to additional physical inventory. A underlift of production from a field is included in current receivables and an overlift of production from a field is included in current liabilities.

INCOME TAX

Income tax expense represents the sum of the tax currently payable and deferred tax.

Current tax

The tax currently payable is based on taxable profit or loss for the year. Taxable profit or loss differs from profit or loss as reported in the statement of profit or loss and other comprehensive income, because it excludes items of income or expense that are taxable or deductible in other years and it further excludes items that are not taxable or tax deductible. The Group's liability for current tax is calculated using tax rates (and tax laws) that have been enacted or substantively enacted, in countries where the Company and its subsidiaries operate, by the end of the reporting period.

Petroleum resource rent tax (PRRT)

PRRT incurred in Australia is considered for accounting purposes to be a tax based on income. Accordingly, current and deferred PRRT expense is measured and disclosed on the same basis as income tax.

PRRT is calculated at the rate of 40% of sales revenues less certain permitted deductions and is tax deductible for income tax purposes. For Australian corporate tax purposes, PRRT payment is treated as a deductible expense, while PRRT refund is treated as an assessable income. Therefore, for the purposes of calculating deferred tax, the PRRT tax rate is combined with the Australian corporate tax rate of 30% to derive a combined effective tax rate of 28%.

Malaysia Petroleum Income Tax (PITA)

PITA incurred in Malaysia is considered for accounting purposes to be a tax based on income derived from petroleum operations. Accordingly, current and deferred PITA expense is measured and disclosed on the same basis as income tax.

PITA is calculated at the rate of 38% of sales revenues less certain permitted deductions and deferred tax is calculated at the same rate.

Deferred tax

Deferred tax is recognised on temporary differences between the carrying amounts of assets and liabilities in the financial statements, and the corresponding tax bases used in the computation of taxable profit. Deferred tax liabilities are generally recognised for all taxable temporary differences and deferred tax assets are recognised to the extent that it is probable that taxable profits will be available, against which deductible temporary differences can be utilised. Such deferred tax assets and liabilities are not utilised if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable profit nor the accounting profit.

Deferred tax liabilities are recognised for taxable temporary differences arising on investments in subsidiaries, except where the Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

Deferred tax assets arising from deductible temporary differences associated with such investments and interests, are only recognised to the extent that it is probable that there will be sufficient taxable profits against which to utilise the benefits of the temporary differences, and they are expected to reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered.

Deferred tax is calculated at the tax rates that are expected to apply in the period when the liability is settled, or the asset realised, based on the tax rates (and tax laws) that have been enacted or substantively enacted, by the end of the reporting period. The measurement of deferred tax liabilities and assets reflects the tax consequences that would follow from the manner in which the Group expects, at the end of the reporting period, to recover or settle the carrying amount of its assets and liabilities.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Group intends to settle its current tax assets and liabilities on a net basis.

Current and deferred tax for the year

Current and deferred tax are recognised as an expense or income in profit or loss, except when they relate to items credited or debited outside profit or loss (either in other comprehensive income or directly in equity), in which case the tax is also recognised outside profit or loss (either in other comprehensive income or directly in equity, respectively).

Other taxes

Revenue, expenses, assets, and liabilities are recognised net of the amount of goods and services tax ("GST") or value added tax ("VAT") except:

- When the GST/VAT incurred on a purchase of goods and services is not recoverable from the taxation authority, in which case the GST/VAT is recognised as part of the cost of acquisition of the asset or as part of the expense item as applicable; and

- Receivables and payables, which are stated with the amount of GST/VAT included.

The net amount of GST/VAT recoverable from, or payable to, the taxation authority is included as part of receivables or payables in the consolidated statement of financial position.

CASH AND BANK BALANCES

Cash and bank balances comprise cash in hand and at bank, and other short-term deposits held by the Group with maturities of less than three months. Restricted cash and cash equivalents balances are those which meet the definition of cash and cash equivalents but are not available for use by the Group.

3. CRITICAL ACCOUNTING JUDGEMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

In the application of the Group's accounting policies, Directors is required to make judgments, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised, if the revision affects only that period, or in the period of the revision and future periods, if the revision affects both current and future periods.

Critical accounting judgments

The following are the critical judgements, apart from those involving estimates (see below) that the Directors have made in the process of applying the Group's accounting policies that have the most significant effect on the amounts recognised in the financial statements.

a) Acquisitions, divestitures and/or assignment of interests

The Group accounts for acquisitions and divestitures by considering if the acquired or transferred interest relates to that of an asset, or of a business as defined in IFRS 3 *Business Combinations* paragraph B7, B8 and Appendix A, in so far as those principles do not conflict with the guidance in IFRS 11 *Joint Arrangements* paragraph 21A. Accordingly, the Group considers if there is the existence of business elements as defined in IFRS 3 (e.g., inputs and substantive processes), or a group of assets that includes inputs and substantial processes that together significantly contribute to the ability to create outputs and providing a return to investors or other economic benefits. The justifications for this assessment on the acquisition of the CWLH Assets have been set out in Note 19.

b) Impairment of oil and gas properties

The Group assesses each asset or cash-generating unit ('CGU') (excluding goodwill, which is assessed annually regardless of indicators) in each reporting period to determine whether any indication of impairment exists. Assessment of indicators of impairment or impairment reversal and the determination of the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment purposes require significant judgement. For example, individual oil and gas properties may form separate CGUs whilst certain oil and gas properties with shared infrastructure may be grouped together to form a single CGU. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing. See Note 12 for details on how these groupings have been determined in relation to the impairment testing of oil and gas properties.

c) Impairment of intangible exploration assets

The Group takes into consideration the technical feasibility and commercial viability of extracting a mineral resource and whether there is any adverse information that will affect the final investment decision. Additionally, the Group performed recoverability assessment for the expenditures incurred based on their cost recoverability in accordance to the terms of the relevant production sharing contracts.

Key sources of estimation uncertainty

The key assumptions concerning the future, and other key sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year, are discussed below.

a) Reserves estimates

The Group's estimated reserves are management assessments, and are independently assessed by an independent third party, which involves reviewing various assumptions, interpretations and assessments. These include assumptions regarding commodity prices, exchange rates, future production, transportation costs, climate related risks and interpretations of geological and geophysical models to make assessments of the quality of reservoirs and the anticipated recoveries. Changes in reported reserves can impact asset carrying amounts, the provision for restoration and the recognition of deferred tax assets, due to changes in expected future cash flows. Reserves are integral to the amount of depreciation, depletion and amortisation charged to the statement of profit or loss and other comprehensive income, and the calculation of inventory. Based on the analysis performed, a 5% decrease in the reserves estimates would result to a further impairment charge of US$60.0 million and a 5% increase in the reserves estimates would reduce the impairment charge by US$17.4 million. TheDirectors consider 5% movements to the existing reserves a reasonable assumption based on the historical technical adjustments during the annual reserves assessment performed by an independent third party and also in view of the mature assets that the Group owns with long production history and therefore less volatility in reserves estimates is anticipated.

b) Impairment of oil and gas properties and intangible exploration assets

For the impairment assessment of oil and gas properties, the Directors assess the recoverable amounts using the VIU approach. The post-tax estimated future cash flows are prepared based on estimated reserves, future production profiles, future hydrocarbon price assumptions and costs. The future hydrocarbon price assumptions used are highly judgemental and may be subject to increased uncertainty given climate change and the global energy transition. The post-tax estimated future cash flows also included the carbon costs estimates of each asset, where applicable. The inclusion of carbon cost estimates of each asset is based on the Directors' best estimate of any expected applicable carbon emission costs payable. This requires Directors' best estimate of how future changes to relevant carbon

carbon emission costs payable. This requires Directors' best estimate of how future changes to relevant carbon emission cost policies and/or legislation are likely to affect the future cash flows of the Group's applicable CGUs, whether enacted or not. Future potential carbon cost estimates of each asset were included to the extent the Directors have sufficient information to make such estimates.

The Directors further take into consideration the impact of climate change on estimated future commodity prices with the application of price assumptions based on economic modelling in scenarios in which the goals of the COP 21 Paris agreement are reached ("Paris aligned price assumptions", see below).

The carrying amounts of intangible exploration assets, oil and gas properties and right-of-use assets are disclosed in Notes 21, 22 and 24, respectively.

The Group recognises that climate change and the energy transition is likely to impact the demand for oil and gas, thus affecting the future prices of these commodities and the timing of decommissioning activities. This in turn may affect the recoverable amount of the Group's oil and gas properties and intangible exploration assets, and the carrying amount of the ARO provision. The Group acknowledges that there is a range of possible energy transition scenarios that may indicate different outcomes for oil prices. There are inherent limitations with scenario analysis and it is difficult to predict which, if any, of the scenarios might eventuate.

The Group has assessed the potential impacts of climate change and the transition to a lower carbon economy in preparing the consolidated financial statements, including the Group's current assumptions relating to demand for oil and gas and their impact on the Group's long-term price assumptions, and also taking into consideration the forecasted long-term prices and demand for oil and gas under the Paris aligned scenarios (IEA's NZE by 2050). The Group's current oil price assumption for internal planning purposes is broadly in line with the IEA's STEPS case, which in turn is underpinned by climate policies and targets already announced by governments. The Group has assessed the potential impacts of climate change and the transition to a lower carbon economy in preparing the consolidated financial statements. This is achieved by running the IEA's NZE scenario through the Group's financial models and assessing the impact on profitability, cash flow and asset values. The IEA's NZE by 2050 case predicts global oil demand will fall from US$97 mb/d in 2022 to US$78 mb/d by 2030 and US$24/mb/d by 2050. Prices fall to US$40/bbl in 2030 and trend lower thereafter. The oil price differential between STEPS and NZE becomes significant from 2030 onwards. The Group monitors energy transition risks and, through its annual risk reviews, challenges its base case assumptions on a regular basis.

The Directors will continue to review various global and regional energy transition developments and their impacts on price assumptions, including Paris aligned scenario price assumptions and demand in line with the scenarios based on decrease to emissions as the energy transition progresses and will continue to take these into consideration in the future impairment assessments. See further disclosures under the Sustainability Review section from pages 13 to 29 in the Group Annual Report.

<u>Sensitivity analyses</u>

The Directors assess the impact of a change in cash flows in impairment testing arising from a 10% reduction in price assumptions used at year end, sourced from independent third party, ERCE and approved by the Directors. The forecasted price assumptions are US$78.5/bbl in 2024, US$79.0/bbl in 2025, US$79.7/bbl in 2026, US$81.2/bbl in 2027 and an average of US$89.8/bbl from 2028 onwards. The Directors are of the view that these price assumptions are aligned with the Group's latest internal forecasts, reflecting long-term views of global supply and demand. The price assumptions used are reviewed and approved by the Directors. Based on the analysis performed, the Directors concluded that a 10% price reduction in isolation under the various scenarios would result to a further impairment charge of US$141.9 million and a 10% price increase in isolation would reduce the impairment charge by US$17.4 million.

The oil price sensitivity analyses above do not, however, represent the Directors' best estimate of any impairments that might be recognised as they do not fully incorporate consequential changes that may arise, such as reductions in costs and changes to business plans, phasing of development, levels of reserves and resources, and production volumes. As an example, as price reduces, it is likely that costs would decrease across the industry. The oil price sensitivity analysis therefore does not reflect a linear relationship between price and value that can be extrapolated.

The Directors also tested the impact of a 5% (2022: 5%) change to the post-tax discount rate used of 10.50% (2022: 10%) for impairment testing of oil and gas properties, and concluded that a 5% increase in the post-tax discount rate would result to a further impairment charge of US$3.4 million and a 5% decrease in the post-tax discount rate would reduce the impairment charge by US$3.5 million.

The Directors assessed the impact of the change in cash flows used in impairment testing arising from the application of the oil price assumptions under the Net Zero Emissions by 2050 Scenario plus the inclusion of carbon cost estimates as disclosed below. The oil prices under the Net Zero Emissions by 2050 Scenario for each asset are as follows:

	2024	**2025**	**2026**	**2027**	**2028**	**2029 onwards**
	US$/bbl	**US$/bbl**	**US$/bbl**	**US$/bbl**	**US$/bbl**	**US$/bbl**
Montara	81.6	77.3	75.6	69.0	62.4	51.3
Stag	81.6	77.3	75.6	69.0	62.4	49.3
CWLH Assets	81.6	77.3	75.6	69.0	62.4	49.8
PenMal Assets - PM323 PSC	81.6	77.3	75.6	69.0	62.4	-
PenMal Assets - PM329 PSC	81.6	77.3	75.6	69.0	62.4	51.3
Lemang PSC	81.6	77.3	75.6	69.0	62.4	49.3

Based on the analysis performed, the reduction in operating cash flows under the Net Zero Emissions by 2050 Scenario would result to a further impairment charge of US$196.8 million to the Group's oil and gas properties. The assumptions under the Net Zero Emissions by 2050 Scenario do not reflect the existing market conditions and are dependent on various factors in the future covering supply, demand, economic and geopolitical events and therefore are inherently uncertain and subject to significant volatility and hence unlikely to reflect the future outcome.

c) Asset restoration obligations

The Group estimates the future removal and restoration costs of oil and gas production facilities, wells, pipelines and related assets at the time of installation of the assets and reviewed subsequently at the end of each reporting period. In most instances the removal of these assets will occur many years in the future.

The estimate of future removal costs is made considering relevant legislation and industry practice and requires the Directors to make judgments regarding the removal date, the extent of restoration activities required and future costs and removal technologies.

The carrying amounts of the Group's ARO is disclosed in Note 37 to the financial statements.

Sensitivity analyses

Sensitivities have been run on the discount rate assumption, with a 1% change being considered a reasonable possible change for the purposes of sensitivity analysis. A 1% reduction in discount rate would increase the liability by US$46.0 million and a 1% increase in discount rate would decrease the liability by US$41.3 million. A 1% increase in the inflation rate would increase the liability by US$46.3 million and a 1% decrease in inflation rate would decrease the liability by US$42.3 million. A 10% increase in current estimated costs would increase the liability by US$61.2 million and a 10% decrease in current estimated costs would decrease the liability by US$61.2 million. A one year deferral to the estimated decommissioning year of each asset as disclosed in Note 37 would decrease the liability by US$30.8 million and an acceleration of one year to the estimated decommissioning year as disclosed in Note 37 would increase the liability by US$7.6 million. TheDirectors consider the 1% movement to the discount rate and inflation rate, 10% to the current estimated costs and one year movement to the estimated decommissioning year a reasonable assumption based on the historical adjustments to the risk-free rates, base decommissioning costs and estimated decommissioning year.

4. REVENUE

The Group presently derives its revenue from contracts with customers for the sale of oil and gas products.

In line with the revenue accounting policies set out in Note 2, all revenue is recognised at a point in time.

	2023 USD'000	2022 USD'000
Liquids revenue	317,469	418,483
Hedging loss (Note 36)	(10,322)	-
	307,147	**418,483**
Gas revenue	2,053	3,119
	309,200	**421,602**

As part of the RBL, during the year,the Group entered into commodity swap contracts to hedge approximately 50% of its forecasted planned production from October 2023 to September 2025. The commodity swap contracts were measured using hedge accounting. See Note 42 for the details of the commodity swap contracts.

5. PRODUCTION COSTS

	2023 USD'000	2022 Restated* USD'000
Operating costs	114,779	100,664
Workovers	17,562	10,190
Logistics	34,109	31,895
Repairs and maintenance	55,572	60,174
Tariffs and transportation costs	7,502	8,341
Decommissioning expenses	12,545	-
Underlift, overlift and crude inventories movement	(9,297)	39,036
	232,772	**250,300**

Operating costs predominately consists of offshore manpower costs of US$26.0 million (2022: US$26.1 million), chemicals, services, supplies and other production related costs for a total of US$49.3 million (2022: US$38.3 million), Malaysian supplementary payments totalled US$10.1 million (2022: US$24.5 million), insurance of US$4.9 million (2022: US$4.8 million) and non-operated assets production costs of US$16.0 million (2022: US$3.3 million). The Malaysian supplementary payments are payable under the terms of PSCs based on the Group's entitlement to profit from oil and gas. It is calculated at 70% of the excess revenue over the base price of the sale of oil as set out under the terms of PSCs. These supplementary payments are made to PETRONAS.

Underlift, overlift and crude inventories movement resulted in a credit of US$9.3 million (2022: US$39.0 million charge), mostly related to higher inventories on hand at Montara and Stag at year end compared to beginning of the year.

Workovers in 2023 and 2022 were recurring in nature. The Group carried out a higher number of workovers at Stag in comparison of 2022.

Repairs and maintenance in current year include Montara storage tank repairs, FPSO maintenance and fabric maintenance costs at both Montara and Stag. In 2022, the costs included Montara Skua-11 repairment works, solar engine change out and emergency tank repairs.

During the year, the previous operator of the PenMal Assets' non-operated PSCs (the "PNLP Assets") has completed the decommissioning works of the FPSO. The decommissioning costs were partially funded by the cess abandonment fund, with the remainder portion of US$12.5 million, net to Jadestone, was funded by the Group's working capital and expensed to profit or loss when incurred.

6. DEPLETION, DEPRECIATION AND AMORTISATION ("DD&A")

	2023 USD'000	2022 Restated* USD'000
Depletion and amortisation (Note 22):	64,575	45,016
Depreciation of:		
Plant and equipment (Note 23)	494	616
Right-of-use assets (Note 24)	15,251	13,015
Crude inventories movement	(4,179)	2,915
	76,141	**61,562**

The crude inventories movement represents additional/reversal of depletion expense recognised during the year based on the net movement of crude inventories at year end against beginning of the year. For the purpose of the consolidated statement of cash flows, this amount has been excluded from the movement in working capital.

The depletion charge is calculated based on units of production and adjusted based on the net movement of crude inventories at year end against beginning of the year. In 2023, the adjustment was for 211,261 bbls of crude inventories at the end of 2023 compared to 90,681 bbls at the end of 2022, mostly due to the restart of production at Montara since March 2023, resulting in a total depletion credit of US$8.2 million.

*Certain 2022 comparative information has been restated. Please refer to Note 50.

7. ADMINISTRATIVE STAFF COSTS

	2023 USD'000	2022 USD'000
Wages, salaries and fees	24,729	24,825
Staff benefits in kind	4,702	3,422
Share-based compensation	766	971
	30,197	**29,218**

The compensations of Directors and key management personnel are included in the above and disclosed separately in Notes 9 and 48, respectively.

8. STAFF NUMBERS AND COSTS

The average number of employees (including Executive Directors) was:

	2023 Number	2022 Number
Production	162	152
Technical	236	206
Administration	2	2
Management	9	9
	409	**369**

Staff costs are split between production costs (Note 5) for offshore personnel and administrative staff costs (Note 7) for onshore personnel.

Their aggregate remuneration comprised:

	2023 USD'000	2022 USD'000
Wages and salaries	47,940	45,548
Social security costs	212	199
Defined contribution pension costs	3,655	3,573
Share-based compensation	766	971
	52,573	**50,291**

Contractors and consultants costs	3,606	4,976
	56,179	**55,267**

9. DIRECTORS' REMUNERATION AND TRANSACTIONS

	2023 USD'000	2022 USD'000
Directors' remuneration		
Salaries, fees, bonuses and benefits in kind	2,496	2,805
Gains on exercise of options		-
Amounts receivable under long term incentive plans	300	341
Money purchase pension contributions	102	78
	2,898	**3,224**
Remuneration of the highest paid Director:		
Salaries, fees, bonuses and benefits in kind	1,028	1,236
Gains on exercise of options	-	-
Amounts receivable under long term incentive plans	210	271
Money purchase pension contributions	65	65
	1,303	**1,572**

	Number	Number
The number of Directors who:		
Are members of a defined benefit pension scheme	-	-
Are members of a money purchase pension scheme	2	2
Exercised options over shares in the Company	-	-
Had awards receivable in the form of shares under a long-term incentive scheme	2	2

The Non-Executive Directors were not granted any options/shares under the Company's long term incentive plans.

10. OTHER EXPENSES

	2023 USD'000	2022 USD'000
Corporate costs	14,179	10,405
Change in provision - Lemang PSC contingent payments	-	7,333
Allowance for slow moving inventories	655	3,768
Assets written off	5,114	212
Net foreign exchange loss	1,728	442
Other expenses	1,165	145
	22,841	**22,305**

Corporate costs include recurring general and administration expenses such as professional fees, office and travelling costs of US$10.5 million (2022: US$8.8 million) and non-recurring costs such as business development costs of US$2.2 million (2022: US$0.8 million), professional fees in relation to internal reorganisation of US$0.8 million (2022: US$0.1 million), equity fundraising of US$0.4 million (2022: nil) and external funding sourcing of US$0.2 million (2022: US$0.2 million).

The change in provision in 2022 was associated with the Lemang PSC contingent payments represents additional contingent payments related to the future Dated Brent prices and Saudi CP prices during the first and second years of production in the Lemang PSC. The provision for these contingent payments were reversed in 2023 (Note 13).

Assets written off in 2023 represents the write off of Montara non-depletable oil and gas properties of US$3.1 million following the cancellation of a capital project for the preparation of Skua-12 well development and written off of obsolete material and spares for US$2.0 million. In 2022, the Group has written off the office equipment located in the New Zealand office following the termination of the Maari acquisition in October 2022.

For the purpose of the consolidated statement of cash flows, the net foreign exchange loss reported above in 2022 included a net unrealised loss of US$0.2 million.

11. AUDITOR'S REMUNERATION

The analysis of the auditor's remuneration is as follows:

	2023 USD'000	2022 USD'000
Fees payable to the Company's auditor for the audit of the parent company and Group's consolidated financial statements	600	544
Audit fees of the subsidiaries	417	390
	1,017	**934**

No fee was paid to the Group's auditor for non-audit services for either the Group or the Company in 2022 or 2023.

The audit fee in prior year represented the actual finalised fee agreed with the auditor.

12. IMPAIRMENT OF ASSETS

	2023 USD'000	2022 USD'000
Impairment of oil and gas properties (Note 22)	29,681	13,534

The impairment expense in 2023 consists of US$17.4 million for the impairment of Stag's oil and gas properties, which is treated as a single cash-generating unit. The impairment is made following the annual impairment assessment performed by the Directors and identified that the VIU of the operating asset, determined based on the post-tax discount rate used of 10.50% (2022: FVLCOD approach was adopted, using post-tax discount rate of 8.99%), is lower than the carrying amount. The impairment was made to reduce the carrying amount of Stag's oil and gas properties to its recoverable amount of US$95.8 million. The key assumptions used in determining the VIU are disclosed Note 3(b). The impairment is made in relation to the producing asset of the Group located in Australia as disclosed in Note 45.

Additionally, the Group also provided impairment of US$12.3 million associated with the adjustment to the ARO estimates for the PNLP Assets (Note 37) that underwent retendering during the year after ceasing production in 2022, following the class suspension of the FPSO, as disclosed on page 36 in the Group Annual Report. The revision of ARO estimates reflects the change on assumptions used for the estimation of the decommissioning costs.

In 2022, the impairment expense was provided in full for the oil and gas properties of the PNLP Asset, which are treated as a single cash-generating unit. The impairment was made following the previous operator's decision to shut in production after FPSO class suspension in February 2022. Accordingly, the VIU of the non-operated PSCs is valued at nil as at the end of 2022.

The impairments for the PNLP Assets in 2023 and 2022 were made in relation to the producing asset of the Group located in Southeast Asia as disclosed in Note 45.

13. OTHER INCOME

	2023 USD'000	2022 USD'000
Interest income	4,451	881
Reversal of provisions - Lemang PSC contingent payments	7,653	-
Net foreign exchange gain	322	341
Insurance claims	-	17,977
Other income	6,429	8,834
	18,855	**28,033**

Interest income consists of US$2.9 million (2022: US$0.1 million) generated from the CWLH Assets abandonment trust fund and US$0.9 million (2022: nil) generated from the Group's fixed term deposits. The abandonment trust funds generates average interest rate of 4.5% (2022: 3.6%) and the fixed term deposits generate average interest rate of 4.5% (2022: nil).

The reversal of provisions associated with the contingent payments for Lemang PSC in 2023 represents the derecognition of contingent payments associated with the Saudi CP and Dated Brent prices due to the trigger events as disclosed on Note 37 are not expected to occur based on the specialist's consensus on Dated Brent prices and the historical correlation between Dated Brent prices and Saudi CP.

Other income mainly consists of rental income from a helicopter rental contract (a right-of-use asset) to a third party of US$6.4 million (2022: US$5.0 million). The other income in 2022 also consisted of an income of US$0.9 million related to amount recognised for previously unrecognised amount due from a joint arrangement partner.

In 2022, insurance claims were made to compensate for loss of production following the drilling of two wells at the Montara field wells in 2020. These claims were resolved and the cash was received in Q4 2022.

For the purpose of the consolidated statement of cash flows, the net foreign exchange gain reported above in 2023 included a net unrealised gain of US$0.2 million (2022: nil).

14. FINANCE COSTS

	2023 USD'000	2022 Restated* USD'000
Interest expense	2,710	5
Accretion expense for:		
Asset restoration obligations (Note 37)	20,201	8,333
RBL (Note 38)	5,517	-
Non-current Lemang PSC VAT receivables	1,182	314
Interest expense on lease liabilities	2,771	769
Warrants expense	3,469	-
Upfront fees on financing facilities	2,656	-
Interest expense on financing facilities	953	-
Changes in fair value of:		
Lemang PSC contingent payments (Note 37)	868	349
CWLH Assets contingent payment (Note 37)	60	-
PenMal Assets contingent payment (Note 37)	-	1,571
RBL commitment fees	349	-
Fair value loss on derivative liability (Note 42)	73	-
Other finance costs	1,020	86
	41,829	**11,427**

The interest expense primarily consists of US$1.3 million (2022: nil) from the US$50.0 million debt facility ("Interim Facility") obtained and repaid during the year and US$1.2 million (2022: nil) from the RBL facility (Note 38).

Warrants expense represents the fair value of the warrant instrument entered into by the Group with Tyrus Capital S.A.M. and funds managed by it, in June 2023.

The Group incurred upfront fees of US$2.7 million (2022: nil) and interest of US$1.0 million (2022: nil) in relation to the equity underwrite debt facility and committed standby working capital facility executed with Tyrus Capital Events S.a.r.l. during the year, see Notes 38 and 49 for further details.

The changes in fair value of the provision associated with the contingent payments for Lemang PSC of US$0.9 million (2022: US$0.3 million) represents fair value adjustments reflecting the effect of the time value of money.

In 2022, the second contingent payment arising from the acquisition of the PenMal Assets was recognised in full for US$3.0 million as at 31 December 2022 (Note 37), resulted in an increase in the provision of US$1.6 million. The amount was recognised as an accrual as at 2022 year end, paid in January 2023.

Other finance costs includes accretion expense of US$0.6 million (2022: nil) generated from an Australian Tax Office ("ATO") repayment plan for corporate tax payments. The repayment schedule is between September 2023 to October 2024.

*Certain 2022 comparative information has been restated. Please refer to Note 50.

15. OTHER FINANCIAL GAINS

	2023 USD'000	2022 USD'000
Accretion income from Australian tax repayment plan	**-**	**1,904**

Accretion income in 2022 was generated from the ATO 2019 repayment plan due to early settlement by the Group in May 2022.

16. INCOME TAX (CREDIT)/EXPENSE

	2023 USD'000	2022 Restated* USD'000
Current tax		
Corporate tax (credit)/charge	(3,403)	15,656
Underprovision in prior years	2,051	666
	(1,352)	**16,322**
Australian petroleum resource rent tax ("PRRT")	1,735	(1,121)
Malaysian petroleum income tax ("PITA")	10,377	11,899

	10,760	**27,100**
Deferred tax		
Corporate tax	(20,138)	14,087
PRRT	(4,269)	7,032
PITA	2,155	5,737
	(22,252)	**26,856**
	(11,492)	**53,956**

Jadestone Energy plc's tax domicile is Singapore and is subjected to Singapore's domestic corporate tax rate of 17%. Subsidiaries are resident for tax purposes in the territories in which they operate.

The Australian corporate income tax rate is applied at 30% of Australian corporate taxable income. PRRT is calculated at 40% of sales revenue less certain permitted deductions and is tax deductible for Australian corporate income tax purposes.

As at year end, Montara and the CWLH Assets have US$3.8 billion (2022: US$3.5 billion) and US$493.4 million (2022: US$535.5 million) of unutilised carried forward PRRT credits, respectively. Based on Directors' latest forecasts, the historic accumulated PRRT net losses are larger than cumulative future expected PRRT taxable profits. Accordingly, Montara and the CWLH Assets are not anticipated to incur any PRRT expense in the future of the asset.

During the year, Stag recorded a net PRRT credit of US$2.5 million (2022: US$5.9 million of PRRT expense).

*Certain 2022 comparative information has been restated. Please refer to Note 50.

The Malaysian corporate income tax is applied at 24% on non-petroleum taxable income. PITA is calculated at 38% of sales revenue less certain permitted deductions and is tax deductible for Malaysian corporate income tax purposes.

PenMal Assets recorded PITA expense of US$12.5 million during the year (2022: US$17.6 million).

The tax recoverable of US$4.1 million as at year end includes of a PITA receivable of US$3.3 million which arose from pre-economic effective date of the PenMal Assets acquisition which will be payable to SapuraOMV following the receipt of a tax refund. The Group has recognised the payable to SapuraOMV as at year end.

The tax expense on the Group's (loss)/profit differs from the amount that would arise using the standard rate of income tax applicable in the countries of operation as explained below:

	2023 **USD'000**	**2022** **Restated*** **USD'000**
(Loss)/Profit before tax	**(102,750)**	**63,193**
Tax calculated at the domestic tax rates applicable to the profit/loss in the respective countries (Australia 30%, Malaysia 24% & 38%, Canada 27% and Singapore 17%)	(27,543)	20,488
Effects of non-deductible expenses	4,003	9,255
Effect of PRRT/PITA tax expense	12,112	10,778
Deferred PRRT/PITA tax (credit)/expense	(2,115)	12,769
Underprovision in prior year	2,051	666
Tax (credit)/expense for the year	**(11,492)**	**53,956**

In addition to the amount charged to the profit or loss, the following amounts relating to tax have been recognised in other comprehensive income.

	2023 **USD'000**	**2022** **USD'000**
Other comprehensive income - deferred tax		
Income tax credit related to carrying amount of hedged item	**(6,056)**	**-**

*Certain 2022 comparative information has been restated. Please refer to Note 50.

17. (LOSS)/PROFIT PER ORDINARY SHARE

The calculation of the basic and diluted loss per share is based on the following data:

	2023 USD'000	2022 Restated* USD'000
(Loss)/Profit for the purposes of basic and diluted per share, being the net (loss)/profit for the year attributable to equity holders of the Company	(91,258)	9,237

	2023 Number	2022 Number
Weighted average number of ordinary shares for the purposes of basic EPS	499,480,437	461,959,228
Effect of diluted potential ordinary shares - share options	-	3,876,548
Effect of diluted potential ordinary shares - performance shares	-	334,163
Effect of diluted potential ordinary shares - restricted shares	-	202,823
Weighted average number of ordinary shares for the purposes of dilutive EPS	**499,480,437**	**466,372,762**

In 2023, 2,493,421 of weighted average potentially dilutive ordinary shares available for exercise from in the money vested options, associated with share options were excluded from the calculation of diluted EPS, as they are anti-dilutive in view of the loss for the year.

In 2023, 79,326 of weighted average contingently issuable shares associated under the Company's performance share plan based on the respective performance measures up to year end were excluded from the calculation of diluted EPS, as they are anti-dilutive in view of the loss for the year.

In 2023, 344,225 of weighted average contingently issuable shares under the Company's restricted share plan were excluded from the calculation of diluted EPS, as they are anti-dilutive in view of the loss for the year.

In 2023, 17,095,890 of weighted average contingently issuable shares under the Company's warrants instrument were excluded from the calculation of diluted EPS, as they are anti-dilutive in view of the loss for the year.

(Loss)/Profit per share (US$)	**2023**	**2022**
- - Basic and diluted	(0.18)	0.02

*Certain 2022 comparative information has been restated. Please refer to Note 50.

18. ACQUISITION OF THE REMAINING 50% INTEREST IN THE PNLP ASSETS

18.1 Effective Date and Acquisition date

On 14 April 2023, Jadestone assumed operatorship of the PNLP Assets following the decision of the previous operator to withdraw from the licences. As part of the takeover, the previous operator paid the Group a sum representing its share of future wells preservation activities and decommissioning costs. The effective date of the takeover is 14 April 2023.

18.2 Asset acquisition

The Directors have concluded that the acquisition of the remaining 50% interest in the PNLP Assets is an asset acquisition as the PNLP Assets does not come with an organised workforce due to the PNLP Assets being shut-in since February 2022 as a result of the class suspension of the Bunga Kertas FPSO which served the PNLP Assets. Additionally, the Group does not take over any process in the form of a system, protocol or standards to contribute to the creation of outputs. Hence, the acquisition does not fall within the definition of a business acquisition under IFRS 3. The value of the assets acquired and liabilities assumed in the acquisition of the remaining 50% interest in the PNLP Assets were allocated on the basis of their relative fair values at the date of acquisition based on sum received from the previous operator.

18.3 Assets acquired and liabilities assumed at the date of acquisition

The value of the identifiable assets and liabilities, acquired and assumed as at the date of acquisition, were allocated on the basis of their relative fair values as follows:

	USD'000
Asset	
Non-current asset	
Other receivables (Note 29)	28,176

	28,176
Liability	
Non-current liability	
Provision for asset retirement obligations (Note 37)	48,430
	48,430
Net identifiable liability acquired	**(20,254)**

19. ACQUISITION OF INTEREST IN CWLH JOINT OPERATION

19.1 Effective Date and Acquisition Date

On 28 July 2022, the Group executed a sale and purchase agreement ("SPA") with BP Developments Australia Pty Ltd ("BP") to acquire BP's non-operated 16.67% working interest in the Cossack, Wanaea, Lambert and Hermes oil field development (the "North West Shelf Project" or "CWLH Assets"), offshore Australia. The initial cash consideration was US$20.0 million plus two contingent payments of US$2.0 million each if the annual average Dated Brent price is equal to or above US$50/bbl in 2022 and US$60/bbl in 2023. Both contingent payment materialised and were paid in January 2023 and 2024, respectively. The second contingent payment was recognised as a payable at 2023 year end.

In addition to the total consideration and as part of this transaction, the Group was required to pay a total of US$82.0 million into a decommissioning trust fund administered by the operator of the CWLH Assets. The first tranche of US$41.0 million was paid immediately prior to closing of the acquisition in November 2022 and two further payments of US$20.5 million each were paid after approval by the Offshore Petroleum & Greenhouse Gas Storage Act (2006) title registration during 2023.

The acquisition completed on 1 November 2022. The acquisition has an economic effective date of 1 January 2020, which meant the Group was entitled to net cash generated since effective date to completion date, resulting in net cash receipts of US$6.9 million at completion on 1 November 2022. On 17 May 2023, the Group received approval from the National Offshore Petroleum Titles Administrator ("NOPTA") for the title transfer.

The legal transfer of ownership and control of the non-operated 16.67% working interest in the CWLH Assets occurred on the date of completion, 1 November 2022 (the "Acquisition Date"). Therefore, for the purpose of calculating the purchase price allocation, the Directors have assessed the fair value of the assets and liabilities associated with the CWLH Assets as at the Acquisition Date.

On 14 November 2023, the Group executed a sale and purchase agreement with Japan Australia LNG (MIMI) Pty Ltd, to acquire additional interests of 16.67% in the CWLH Assets. See Note 48 for further details.

19.2 Acquisition of a 16.67% non-operated working interest

The CWLH Assets contain inputs (working interest in the CWLH Assets) and processes (existing organised workforce and onshore and offshore infrastructures managed by the operator), which when combined has the ability to contribute to the creation of outputs (oil). Accordingly, the CWLH Assets constitute a business and as a consequence, we have accounted for our acquisition of a 16.67% working interest in those assets using the accounting principles of business combinations accounting as set out in IFRS 3, and other IFRSs as required by the guidance in IFRS 11 paragraph 21A.

A purchase price allocation exercise was performed to identify, and measure at fair value, the assets acquired and liabilities assumed in the business combination. The consideration transferred was measured at fair value. The Group has adopted the definition of fair value under IFRS 13 *Fair Value Measurement* to determine the fair values, by applying Level 3 of the fair value measurement hierarchy.

19.3 Fair value of consideration

After taking into account various adjustments the net consideration for the CWLH Assets resulted in a cash receipt of US$6.9 million, as set out below:

	USD'000
Asset purchase price	20,000
Closing statement adjustments	(26,953)
Net cash receipts from the acquisition	**(6,953)***

Fair value of purchase consideration	**USD'000**
Asset purchase price	20,000
Closing statement adjustments	(26,953)
Net cash receipts from the acquisition	**(6,953)***
Deferred contingent consideration	3,940
Fair value of purchase consideration	**(3,013)**

* For the purpose of the consolidated statement of cash flows, the Group received US$5.8 million from BP on the

Acquisition Date, with the remaining US$1.2 million recognised as a receivable as at 2022 year end. This cash amount was received in February 2023.

The Group considers that the purchase consideration and the transaction terms to be reflective of fair value for the following reasons:

- Open and unrestricted market: there were no restrictions in place preventing other potential buyers from negotiating with BP during the sales process period and there were a number of other interested parties in the formal sale process;

- Knowledgeable, willing and non-distressed parties: both the Group and BP are experienced oil and gas operators under no duress to buy or sell. The process was conducted over several months which gave both parties sufficient time to conduct due diligence and prepare analysis to support the transaction; and

- Arm's length nature: the Group is not a related party to BP. Both parties had engaged their own professional advisors. There is no reason to conclude that the transaction was not transacted at arm's length.

19.4 Assets acquired and liabilities assumed at the date of acquisition

During the year, the Group has completed the purchase price assessment ("PPA") to determine the fair values of the net assets acquired within 12 months from the Acquisition Date. A PPA adjustment was made in relation to the ARO provision and recognition of deferred tax asset associated with the provision for asset restoration obligations following additional information obtained subsequent to the acquisition of the CWLH Assets. The adjusted fair values of the identifiable assets and liabilities have been reflected in the consolidated statement of financial position as at 31 December 2022.

Below are the effects of the final PPA adjustments in accordance with IFRS 3:

	Provisional PPA USD'000	Adjustments USD'000	Final PPA USD'000
Asset			
Non-current asset			
Oil and gas properties (Note 22)	41,976	(21,307)	20,669
Deferred tax assets	-	19,390	19,390
Current asset			
Trade and other receivables	27,870	-	27,870*
	69,846	**(1,917)**	**67,929**
Liabilities			
Non-current liabilities			
Provision for asset restoration obligations (Note 37)	60,158	4,475	64,633
Deferred tax liabilities	12,593	(6,392)	6,201
Current liability			
Trade and other payables	108	-	108
	72,859	**(1,917)**	**70,942**
Net identifiable liabilities assumed	**(3,013)**	**-**	**(3,013)**

* Trade and other receivables consisted of a gross underlift position of 314,078 bbls acquired by the Group, with a fair value of US$27.3 million, measured at the prevailing market price of US$86.68/bbl. The underlift position was recognised as an expense following a lifting which occurred in the middle of November 2022. The balance also included a gross cash overcall position owing by the operator of US$0.6 million as at the acquisition date. The overcall position will be unwound in the future based on the joint arrangement expenditures claim raised by the operator. No loss allowances have been recognised in respect to trade and other receivables.

Please refer to Note 50 for a summary of the adjustment of comparative figures.

19.5 Impact of acquisition on the results of the Group

The Group's 2022 results included US$56.6 million of revenue and US$9.3 million of after tax profit attributable to the CWLH Assets.

Acquisition-related costs amounting to US$0.5 million have been excluded from the consideration transferred and have been recognised as an expense in the prior year, within "other expenses" line item in the consolidated statement of profit or loss and other comprehensive income.

Had the business combination been effected at 1 January 2022, and based on the performance of the business during 2022 under BP, the Group would have generated revenues of US$109.6 million and an estimated net profit after tax of US$29.5 million.

20. ACQUISITION OF 10% INTEREST IN LEMANG PSC

20.1 Acquisition date

On 23 November 2022, the Groupcompleted the acquisition of the remaining 10% interest in the Lemang PSC. As a result, Jadestone's interest (pre local government back-in rights) in the Lemang PSC has increased to 100%.

The 10% interest was acquired through the execution of a Settlement and Transfer Agreement ("STA") between the Group and PT Hexindo Gemilang Jaya ("Hexindo"). In return for the transfer of Hexindo's 10% stake, the Group released Hexindo from unpaid amounts of US$1.4 million relating to Hexindo's interest in the Lemang PSC, which consisted of US$0.4 million (Note 29) generated since 11 December 2020 when the Group first acquired the 90% working interest in the Lemang PSC up to the STA date of 23 November 2021, plus US$1.0 million which arose prior to 11 December 2020. Additionally, the Group paid a cash consideration of US$0.5 million (inclusive of transfer taxes, which the Group has remitted directly to the Indonesian government).

20.2 Assets acquired and liabilities assumed at the date of acquisition

The assets and liabilities associated with the 10% interest in the Lemang PSC, acquired and assumed as at the date of acquisition, were:

	USD'000
Asset	
Non-current assets	
Oil and gas properties (Note 22)	1,414
VAT receivables	1,338
Current assets	
Trade and other receivables	15
Inventories	26
	2,793
Liabilities	
Non-current liability	
Provision for asset restoration obligations (Note 37)	337
Current liability	
Trade and other payables	598
	935
Net identifiable assets acquired	**1,858**

The provision for ARO assumed by the Group is associated with historical oil production by Mandala Energy that ceased in 2016, prior to the acquisition of the 90% operated interest by the Group in December 2020. The obligation was assumed following the acquisition, and the decommissioning expenditure is expected to be incurred from 2036, at the end of the life of the planned gas development.

21. INTANGIBLE EXPLORATION ASSETS

	USD'000
Cost	
As at 1 January 2022	93,241
Additions	3,582 (a)
Transfer	(18,895) (b)
As at 31 December 2022	**77,928**
Additions	1,636 (a)
As at 31 December 2023	**79,564**
Impairment	
As at 1 January 2022 and 1 January 2023	-
Additions (Note 12)	-
As at 31 December 2023	**-**
Carrying amount	
As at 1 January 2022	**93,241**
As at 31 December 2022	**77,928**

As at 31 December 2023	**79,564**

[a] For the purpose of the consolidated statement of cash flows, current year expenditure on intangible exploration assets of US$0.1 million remained unpaid as at 31 December 2023 (2022: US$0.3 million).

[b] The transfer relates to the Lemang PSC in Indonesia. In June 2022, the final investment decision was taken following regulatory approval to award the engineering, procurement, construction and installation ("EPCI") contract which established commercial viability. The capitalised cost of US$18.9 million was transferred to development assets as disclosed in Note 22.

22. OIL AND GAS PROPERTIES

	Production assets USD'000	Development assets USD'000	Total USD'000
Cost			
As at 1 January 2022	595,494	-	595,494
Changes in asset restoration obligations (Note 37)	18,680	7	18,687
Acquisition of CWLH Assets (Note 19)	20,669	-	20,669
Acquisition of 10% interest in Lemang PSC (Note 20)	-	1,414	1,414
Additions	62,319	16,619	78,938[a]
Written off	(3,704)	-	(3,704)[b]
Transfer	-	18,895	18,895
As at 31 December 2022 (Restated)*	**693,458**	**36,935**	**730,393**
Changes in asset restoration obligations (Note 37)	7,150	-	7,150[a]
Additions	32,058	81,672	113,730[b][e]
Transfer of 50% interest in PNLP Assets	48,430	-	48,430[d]
Written off	(3,067)	-	(3,067)
As at 31 December 2023	**778,029**	**118,607**	**896,636**
Accumulated depletion, amortisation and impairment			
As at 1 January 2022	241,902	-	241,902
Charge for the year	45,016	-	45,016
Impairment	13,534	-	13,534
Written off	(3,704)	-	(3,704)[c]
As at 31 December 2022 (Restated)*	**296,748**	**-**	**296,748**
Charge for the year	64,575	-	64,575
Impairment	78,111	-	78,111[d]
As at 31 December 2023	**439,434**	**-**	**439,434**
Carrying amount			
As at 1 January 2022	**353,592**	**-**	**353,592**
As at 31 December 2022	**396,710**	**36,935**	**433,645**
As at 31 December 2023	**338,595**	**118,607**	**457,202**

*Certain 2022 comparative information has been restated. Please refer to Note 50.

[a] The changes in ARO in Note 37 of US$19.4 million includes the increase in ARO of the PNLP Assets of US$24.5 million while the changes in ARO of US$7.2 million in this note includes the increase in ARO of the PNLP Assets of US$12.3 million, being 50% of the working interests owned by the Group. The remaining 50% for the increase in ARO of the PNLP Assets of US$12.3 million is offset against the non-current other payable (Note 41) due to the costs are to be funded from the cash advances receivable from the Malaysian joint arrangement partner for its share future decommissioning costs on the PNLP Assets when it withdrew from the licences in 2023.

[b] The additions in 2023 and 2022 represents cash paid for the Group's capital expenditure projects. The additions in 2023 includes the capitalisation of borrowing costs of US$2.4 million.

[c] The written off amount in 2022 represented the fully depreciated oil and gas properties associated with the Indonesian

Ogan Komering PSC of which the PSC had expired in 2018.

(d) On 14 April 2023, Jadestone assumed operatorship of the PNLP Assets following the decision of the previous operator to withdraw. Accordingly, the Group has assumed the previous operator's share of decommissioning liabilities of US$48.4 million following the transfer of operatorship, with a corresponding increase to the oil and gas properties balance. The Directors have assessed the recoverable amount of the oil and gas properties acquired following the takeover to be zero using the VIU approach. Accordingly, the oil and gas properties were fully impaired and offset against the non-current other payable (Note 41) for the reason as explained in (a) above, due to the uncertainty in respect to a potential restart date for production under the PSCs and as a result there is no certainty of future cash flows from the oil and gas properties. On 31 October 2023, MPM[1] invited Jadestone to participate in the bidding for the renamed PNLP assets, which is now referred to as the "Puteri Cluster PSC," through Malaysia Bid Round Plus ("MBR+"). The Group submitted its bid in January 2024, with results of the bidding anticipated in May 2024. The Directors are reasonably confident that the bid will be successful but there is no certainty of success and future cash flows from the assets.

The remaining impairment amount consists of the impairment of Stag's oil and gas properties for US$17.4 million and PNLP Assets' oil and gas properties for US$12.3 million as further disclosed in Note 12.

(e) For the purpose of the consolidated statement of cash flows, current year expenditure on oil and gas properties of US$3.8 million remained unpaid as at 31 December 2023 (2022: nil).

[1] Malaysia Petroleum Management ("MPM") is entrusted to act for and on behalf of PETRONAS in the overall management of Malaysia's petroleum resources.

23. PLANT AND EQUIPMENT

	Computer equipment USD'000	Fixtures and fittings USD'000	Materials and spares USD'000	Total USD'000
Cost				
As at 1 January 2022	3,554	1,571	7,209	12,334
Additions	204	152	-	356
Written off	(313)	(14)	-	(327)
Transfer	-	-	(1,173)	(1,173)[(a)]
As at 31 December 2022	**3,445**	**1,709**	**6,036**	**11,190**
Additions	280	236	-	516
Transfer	-	-	3,122	3,122[(a)]
As at 31 December 2023	**3,725**	**1,945**	**9,158**	**14,828**
Accumulated depreciation				
As at 1 January 2022	1,959	1,412	-	3,371
Charge for the year	450	166	-	616
Written off	(101)	(14)	-	(115)
As at 31 December 2022	**2,308**	**1,564**	**-**	**3,872**
Charge for the year	347	147	-	494
As at 31 December 2023	**2,655**	**1,711**	**-**	**4,366**
Carrying amount				
As at 1 January 2022	**1,595**	**159**	**7,209**	**8,963**
As at 31 December 2022	**1,137**	**145**	**6,036**	**7,318**
As at 31 December 2023	**1,070**	**235**	**9,158**	**10,462**

(a)

[d] The transfer represents the material and spares that are not expected to be consumed within the next 12 months from the year end. The reclassification amount is net of allowance of slow moving items of US$1.7 million (2022: US$2.7 million).

24. RIGHT-OF-USE ASSETS

	Transportation and logistics USD'000	Buildings USD'000	Total USD'000
Cost			
As at 1 January 2022	43,545	4,823	48,368
Additions	6,701	655	7,356
Written off*	(4,146)	(1,835)	(5,981)
As at 31 December 2022	**46,100**	**3,643**	**49,743**
Additions	36,926	1,231	38,157
Written off*	(39,673)	-	(39,673)
As at 31 December 2023	**43,353**	**4,874**	**48,227**
Accumulated depreciation			
As at 1 January 2022	31,408	3,108	34,516
Charge for the year	12,224	791	13,015
Written off*	(4,146)	(1,835)	(5,981)
As at 31 December 2022	**39,486**	**2,064**	**41,550**
Charge for the year	14,390	861	15,251
Written off*	(39,673)	-	(39,673)
As at 31 December 2023	**14,203**	**2,925**	**17,128**
Carrying amount			
As at 1 January 2022	**12,137**	**1,707**	**13,852**
As at 31 December 2022	**6,614**	**1,579**	**8,193**
As at 31 December 2023	**29,150**	**1,948**	**31,099**

* This represents the write off of expired leases.

Most of the Group's right-of-use assets are contracts to lease assets including helicopters, a supply boat, logistic facilities for the Montara field and buildings. The average lease term is 2.7 years. The additions to right-of-use assets during the year mainly consist of the extension of the Group's helicopter lease and Montara warehouse lease for three years and two years, respectively, plus a two-year lease for Montara vessel to replace an expired lease.

The maturity analysis of lease liabilities is presented in Note 39.

	2023 USD'000	2022 USD'000
Amount recognised in profit or loss		
Depreciation expense on right-of-use assets	15,251	13,015
Interest expense on lease liabilities	2,771	769
Expenses relating to short-term leases	36,680	16,028
Expense relating to leases of low value assets	44	68

As at 31 December 2023, the Group is committed to US$3.9 million of short-term leases (2022: US$3.0 million).

The total cash outflow in 2023 relating to leases was US$53.9 million (2022: US$30.8 million).

25. INVESTMENT IN ASSOCIATE

	2023 USD'000	2022 USD'000
At beginning of year	-	-
Acquisition of 9.52% non-operated interest in Sinphuhorm Assets	27,853	-
Dividends received during the year	(3,842)	
Share of profit of the associate	2,640	
At end of year	**26,651**	**-**

On 19 January 2023, the Group executed a sale and purchase agreement with Salamander Energy (S.E. Asia) Limited, an affiliate of PT Medco Energi Internasional Tbk, to acquire its interest in three legal entities, which collectively own a 9.52%

non-operated interest in the producing Sinphuhorm gas field and a 27.2% interest in the Dong Mun gas discovery onshore north-east Thailand. The acquisition included a 27.2% interest in APICO LLC, which operates the Sinphuhorm concessions (E5N and EU1) and Dong Mun (L27/43). The acquisition was completed on 23 February 2023, for a cash consideration of US$27.9 million. The acquisition has an economic effective date of 1 January 2022, which meant the Group was entitled to net cash generated since effective date to completion date.

APICO LLC is limited liability company incorporated in the State of Delaware, United States of America. Its primary business purpose is the acquisition, exploration, development and production of petroleum interests in the Kingdom of Thailand. Its principal activities are currently exploration in operated concessions and gas production in non-operated concessions.

The Group has applied equity accounting for the investment in associate. The summarised financial information in respect of the associate, APICO LLC, since the date of acquisition of 23 February 2023 is set out below. The summarised financial information below represents amounts in associates' financial statements which holds a 35% interest in the Sinphuhorm gas field. The APICO LLC's financial statements are prepared in accordance with IFRS Accounting Standards.

	2023 **USD'000**
Current assets	39,027
Non-current assets	133,037
Current liabilities	27,048
Non-current liabilities	6,902
Revenue	59,504
Profit before tax	26,412
Profit after tax, representing total comprehensive income for the year	9,705
Proportion of the Group's ownership interest in the associate	27.2%
Share of profit of the associate	2,640
Dividends received from the associate during the year	(3,842)

26. INTERESTS IN OPERATIONS

Details of the operations, of which all are in production except for 46/07 and 51 which are in the exploration stage while the Lemang PSC is in the development stage, are as follows:

Contract Area	**Date of expiry**	**Held by**	**Place of operations**	**Group effective working interest % as at 31 December**	
				2023	**2022**
Montara oilfield	Indefinite	Jadestone Energy (Eagle) Pty Ltd	Australia	100	100
Stag Oilfield	25 August 2039	Jadestone Energy (Australia) Pty Ltd	Australia	100	100
PM329	8 December 2031	Jadestone Energy (Malaysia) Pte Ltd	Malaysia	70	70
PM323	14 June 2028	Jadestone Energy (Malaysia) Pte Ltd	Malaysia	60	60
PM318	24 May 2034	Jadestone Energy (PM) Inc.	Malaysia	100	50
AAKBNLP	24 May 2024	Jadestone Energy (PM) Inc.	Malaysia	100	50
WA-3-L	Indefinite	Jadestone Energy (CWLH) Pty Ltd	Australia	17	17
WA-9-L	15 July 2033	Jadestone Energy (CWLH) Pty Ltd	Australia	17	17
WA-11-L	4 September 2035	Jadestone Energy (CWLH) Pty Ltd	Australia	17	17
WA-16-L	11 September 2039	Jadestone Energy (CWLH) Pty Ltd	Australia	17	17
46/07	29 June 2035	Mitra Energy (Vietnam Nam Du) Pte Ltd	Vietnam	100	100
51	10 June 2040	Mitra Energy (Vietnam Tho Chu) Pte Ltd	Vietnam	100	100
Lemang	17 January 2037	Jadestone Energy (Lemang) Pte Ltd	Indonesia	100	100
Sinphuhorm concessions (E5N)	15 March 2031	Jadestone Energy (Thailand) Pte Ltd	Thailand	10	-
Sinphuhorm concessions (EU1)	2 June 2029	Jadestone Energy (Thailand) Pte Ltd	Thailand	10	-
Dong Mun (L27/43)	24 September 2017[1]	Jadestone Energy (Thailand) Pte Ltd	Singapore	27	-

1 The application for the extension to the license is currently ongoing and managed by the associate, APICO LLC.

27. DEFERRED TAX

The following are the deferred tax liabilities and assets recognised by the Group and movements thereon.

	Australian PRRT USD'000	Malaysian PITA USD'000	Tax depreciation USD'000	Derivative financial instruments USD'000	Total USD'000
As at 1 January 2022 (Restated)*	14,546	7,342	(75,584)	-	(53,696)
Charged to profit or loss (Note 16)	(7,032)	(5,737)	(14,087)	-	(26,856)
Acquisition of CWLH Assets (Note 19)	(6,201)	-	19,390	-	13,189
As at 31 December 2022 (Restated)*	**1,313**	**1,605**	**(70,281)**	**-**	**(67,363)**
Charged to profit or loss (Note 16)	4,269	(2,155)	20,138	-	22,252
Credited to OCI	-	-	-	6,056	6,056
As at 31 December 2023	**5,582**	**(550)**	**(50,143)**	**6,056**	**(39,055)**

The following is the analysis of the deferred tax balances (after offset) for financial reporting purposes:

	31 December 2023 USD'000	31 December 2022 Restated* USD'000	1 January 2022 Restated* USD'000
Deferred tax liabilities	(65,829)	(76,481)	(77,562)
Deferred tax assets	26,774	9,118	23,866
	(39,055)	**(67,363)**	**(53,696)**

The Group's deferred tax assets predominately arising from its Australian operations and PenMal Assets. Deferred tax assets are recognised as the Directors believe there will be sufficient taxable profits from its Australian and Malaysian producing assets to offset against the available future deductions based on the estimated future cash flows prepared.

The Group has unutilised PRRT credits of approximately US$3.8 billion (2022: US$3.5 billion; 2021: US$3.4 billion) and US$493.4 million (2022: US$535.5 million; 2021: nil) available for offset against future PRRT taxable profits in respect of the Montara field and the CWLH Assets, respectively. The PRRT credits remain effective throughout the production licence of Montara and the CWLH Assets. No deferred tax asset has been recognised in respect of these PRRT credits, due to the Directors' projections that the historic accumulated PRRT net losses are larger than cumulative future expected PRRT taxable profits. As PRRT credits are utilised based on a last-in-first-out basis, the unutilised PRRT credits of approximately US$3.8 billion (2022: US$3.5 billion; 2021: US$3.4 billion) and US$493.4 million (2022: US$535.5 million; 2021: nil) with respect to Montara and the CWLH Assets are not expected to be utilised and are therefore not recognised as a deferred tax asset.

*Certain 2022 comparative information has been restated. Please refer to Note 50.

28. INVENTORIES

	2023 USD'000	2022 Reclassified* USD'000
Materials and spares	23,242	18,969
Less: allowance for slow moving (Note 10)	(7,010)	(6,334)
	16,232	**12,635**
Crude oil inventories	17,422	7,009
	33,654	**19,644**

The cost of inventories recognised as an expense during the year for lifted volumes, is calculated by including production costs excluding workovers, Malaysian supplementary payments and tariffs and transportation costs, plus depletion expense of oil & gas properties, and plus depreciation of right-of-use assets deployed for operational use. In 2023, this cost totalled US$274.4 million (2022: US$260.4 million).

29. TRADE AND OTHER RECEIVABLES

	2023	2022
		Reclassified*
	USD'000	USD'000
Current assets		
Trade receivables	12,533	6,332
Prepayments	5,947	3,119
Other receivables and deposits	88,005	4,126
Amount due from joint arrangement partners (net)	12,911	4,268
Underlift crude oil inventories	3,539	107
GST/VAT receivables	1,444	1,683
	124,379	**19,635**
Non-current assets		
Other receivables	127,730	83,192
VAT receivables	14,130	7,398
	141,860	**90,590**
	266,239	**110,225**

Trade receivables arise from revenues generated from the Group's respective sole customer in Australia and Malaysia. The average credit period is 30 days (2022: 30 days). All outstanding receivables as at 31 December 2023 and 2022 have been recovered in full in 2024 and 2023, respectively.

*Certain 2022 comparative information has been reclassified between line items. Please refer to Note 50.

The current other receivables as at 31 December 2023 mainly represent the accumulated cess payment paid to the Malaysian regulator for the PenMal PNLP Assets and an amount due from a joint arrangement partner for its share of future wells preservation activities and decommissioning costs when it exited two PSC licences during 2023. The receivable was received in January 2024.

Amount due from joint arrangement partners represents cash calls receivable from the Malaysian joint arrangement partner, net of joint arrangement expenditures. The amount is unsecured, with a credit period of 15 days. A notice of default will be served to the joint arrangement partner if the credit period is exceeded, which will become effective seven days after service of such notice if the outstanding amount remains unpaid. Interest of 3% per annum will be imposed on the outstanding amount, starting from the effective date of default. The outstanding receivable was received in January 2024.

The underlift crude oil inventories represent entitlement imbalances at year end of 54,079 bbls at the PenMal operated assets. The underlift position is measured at cost of US$18.75/bbl. The 2023 underlift position will unwind in 2024 based on the subsequent net productions entitled to the Group. The Group was in overlift position at 2022 year end which unwound in 2023 based on actual production entitlement during the year. The underlift crude oil inventories also consist of 32,411 bbls at the PNLP Assets being the underlift position inherited by the Group following the assumption of operatorship of the PNLP Assets from the previous operator. The underlift position is measured at fair value of US$77.91/bbl in view of there was no production at the PNLP Assets during the year.

Non-current other receivables represent the accumulated cess payment paid to the Malaysian and Indonesian regulators for the operated licences and an abandonment trust fund set up following the acquisition of the CWLH Assets. The Malaysian PSCs and Lemang PSC require upstream operators to contribute periodic cess payments to a cess abandonment fund throughout the production life of the upstream oil and gas assets, while the abandonment trust fund was set up as part of the acquisition of the CWLH Assets. The payments made were to ensure there are sufficient funds available for decommissioning expenditures activities at the end of the fields' life. The cess payment amount is assessed based on the estimated future decommissioning expenditures.

The increase of non-current other receivables during the period represents additional payments of US$41.0 million into the CWLH abandonment trust fund. Additionally, the total accumulated cess payment paid to the Malaysian regulator and the ARO provision for the PNLP Assets are now presented on a gross basis following the reallocation of the CESS funds when the licenses and operatorship were transferred to the Group in April 2023, in line with the Group's accounting policies. In 2022, the total accumulated cess payment paid and the ARO provision was presented on a net basis to reflect the PSCs were non-operated, in line with the Group's accounting policies. See Note 37 for further details.

The non-current VAT receivables are associated with the Lemang PSC. It is classified as a non-current asset as the recovery of the VAT receivables is dependent on the share of revenue entitlement by the Indonesian government after the commencement of gas production, which is expected to occur in the first half of 2024.

There are no trade receivables older than 30 days. The credit risk associated with the trade receivables is disclosed in Note 44.

30. CASH AND BANK BALANCES

	2023	2022
	USD'000	USD'000
Cash and bank balances, representing cash and cash equivalents in the consolidated statement of cash flows, presented as:		
Non-current	1,008	676
Current	152,396	122,653
	153,404	**123,329**

The non-current cash and cash equivalents represents the restricted cash balance of US$0.7 million (2022: US$0.4 million) and US$0.3 million (2022: US$0.3 million) in relation to a deposit placed for bank guarantee with respect to the PenMal Assets and Australian office building, respectively. These bank guarantees are expected to be in place for a period of more than twelve months.

Current cash and cash equivalents include a bank guarantee of US$0.5 million placed by the Group during the year with respect to the construction of the Lemang PSC gas pipeline facilities. This bank guarantee expired in February 2024.

As part of the RBL facility, the Group must retain an aggregate amount of principal, interest, fees and costs payable for the next two quarters in the debt service reserve account ("DSRA"). An amount of US$8.2 million was deposited into the DSRA during 2023 and it is classified as a current asset.

31. SHARE CAPITAL AND SHARE PREMIUM ACCOUNT

	No. of shares	Share capital USD'000	Share premium account USD'000
Issued and fully paid			
As at 1 January 2022, at £0.001 each	465,081,238	358	201
Issued during the year	1,446,108	2	782
Share repurchased	(18,173,683)	(21)	-
As at 31 December 2022	**448,353,663**	**339**	**983**
Issued during the year	94,463,933	120	50,844
Share repurchased	(2,051,022)	(3)	-
As at 31 December 2023	**540,766,574**	**456**	**51,827**

On 2 August 2022, the Company announced the launch of a share buyback programme (the "Programme") in accordance with the authority granted by the shareholders at the Company's annual general meeting on 30 June 2022. The maximum amount of the Programme was US$25.0 million, and the Programme will not exceed 46,574,528 ordinary shares.

On 19 January 2023, the Companysuspended its share buyback programme. For the year ended 31 December 2023, the Company had acquired 2.3 million shares at a weighted average cost of GB£0.75 per share, resulting in total expenditure of US$2.1 million. The total nominal value of the shares repurchased was US$2,485. All shares repurchased were cancelled. Since the launch of the share buyback programme, a total of 20.4 million shares had been acquired for a total accumulated expenditure of US$18.1 million, with total nominal value of the shares repurchased was US$23,778.

As at 31 December 2022, the Company did not have a liability in respect to the remaining unutilised amount of US$8.9 million under the Programme as the Company had full discretion over the number of shares to be repurchased. The Programme expired on 30 June 2023 in conjunction with the Company's 2023 annual general meeting ("AGM") and was not renewed at the 2023 AGM.

On 6 June 2023, the Company completed an equity fundraising, creating an additional 94,081,826 ordinary shares at GB£0.45 per share, which comprised of a placing and subscription of 92,312,691 new ordinary shares to existing and new institutional shareholders and a placing and subscription of 1,769,135 new ordinary shares to the Directors of the Company. Total gross proceeds were US$53.0 million, with net proceeds of US$51.0 million. The Group incurred total costs of US$2.0 million associated with the equity fundraising and these costs were accounted as a deduction to the equity.

On 9 June 2023, the Company launched an open offer of up to 14,887,039 new ordinary shares, at GB£0.45 per share, to raise additional proceeds of up to EUR8.0 million[1] (up to US$8.6 million). The open offer closed on 28 June 2023, raising a total gross and net proceeds of US$42,009 by issuing 73,557 new shares.

During the year, employee share options of 128,160 were exercised and issued at an average price of GB£ 0.56 per share (2022: 1,446,108; GB£0.42 per share). Additionally, 79,327 shares were issued during the year to satisfy the Company's obligations with regards to the performance shares and 101,063 shares were issued to meet the obligations with regards to the restricted shares.

The Company has one class of ordinary share. Fully paid ordinary shares with par value of GB£0.001 per share carry one vote per share without restriction, and carry a right to dividends as and when declared by the Company.

1 The open offer was quoted in Euro of 8.0 million to meet the applicable regulation issued by the European Union regarding to the quantum of open offer.

32. DIVIDENDS

The parent company has sufficient distributable reserves to declare dividends. The distributable reserves were created through the reduction of share capital of the Company in May 2021. The dividends declared in 2022 were in compliance with the Act.

The Company did not declare any dividend during the year.

On 20 September 2022, the Directors declared a 2022 interim dividend of 0.65 US cents/share, equivalent to a total distribution of US$3.0 million. The dividend was paid on 11 October 2022.

On 6 June 2022, the Directors recommended a final 2021 dividend of 1.34 US cents/share, equivalent to a total distribution of US$6.2 million, or US$9.0 million in respect of total 2021 dividends. The dividend was approved by shareholders on 30 of US$6.2 million, or US$9.0 million in respect of total 2021 dividends. The dividend was approved by shareholders on 30 June 2022 and paid on 5 July 2022.

33. MERGER RESERVE

The merger reserve arose from the difference between the carrying value and the nominal value of the shares of the Company, following completion of the internal reorganisation in 2021.

34. SHARE-BASED PAYMENTS RESERVE

The total expense arising from share-based payments of US$0.8 million (2022: US$1.0 million) was recognised as 'administrative staff costs' (Note 7) in profit or loss for the year ended 31 December 2023. The share-based payment expense arise from share options, performance shares and restricted shares awarded from 2020 to 2022. In view of the performance of the Group in 2023, the Remuneration Committee suspended performance share grants in 2023. In consultation with an external advisor, the Remuneration Committee approved a Deferred Cash Plan ("DCP") for the 2023 - 2026 Long-Term Incentive ("LTI") cycle, which was awarded in October 2023 (Note 41). This was done to ensure that the LTI programme aligns the interests of the senior leaders of the Group to the interests of shareholders, and is effective in retaining and incentivising our top talents.

On 15 May 2019, the Company adopted, as approved by the shareholders, the amended and restated stock option plan, the performance share plan, and the restricted share plan (together, the "LTI Plans"), which establishes a rolling number of shares issuable under the LTI Plans up to a maximum of 10% of the Company's issued and outstanding ordinary shares at any given time. Options under the stock option plan will be exercisable over periods of up to 10 years as determined by the Board.

34.1 Share options

The Directors have applied the Black-Scholes option-pricing model, with the following assumptions, to estimate the fair value of the options at the date of grant:

	Options granted on 9 March 2022
Risk-free rate	1.34% to 1.38%
Expected life	5.5 to 6.5 years
Expected volatility[1]	63.0% to 66.7%
Share price	GB£ 1.01
Exercise price	GB£ 0.92
Expected dividends	1.96%

34.2 Performance shares

The performance measures for performance shares incorporate both a relative and absolute total shareholder return ("TSR") calculation on a 70:30 basis to compare performance vs. peers (relative TSR) and to ensure alignment with shareholders (absolute TSR).

Relative TSR: measured against the TSR of peer companies; the size of the payout is based on Jadestone's ranking against the TSR outcomes of peer companies.

Absolute TSR: share price target plus dividend to be set at the start of the performance period and assessed annually; the threshold share price plus dividend has to be equal to or greater than a 10% increase in absolute terms to earn any pay out at all, and must be 25% or greater for target pay out.

A Monte Carlo simulation model was used by an external specialist, with the following assumptions to estimate the fair value of the performance shares at the date of grant:

	Performance shares granted on 9 March 2022
Risk-free rate	1.39%
Expected volatility	53.1%
Share price	GB£ 1.01
Exercise price	N/A
Expected dividends	1.71%
Post-vesting withdrawal date	N/A
Early exercise assumption	N/A

[1] Expected volatility was determined by calculating the average historical volatility of the daily share price returns over a period commensurate

[1] Expected volatility was determined by calculating the average historical volatility of the daily share price returns over a period commensurate with the expected life of the awards for a group of ten peer companies.

[2] Expected volatility was determined by calculating Jadestone's average historical volatility of each trading day's log growth of TSR over a period between the grant date and the end of the performance period.

34.3 Restricted shares

Restricted shares are granted to certain senior management personnel as an alternative to cash under exceptional circumstances and to provide greater alignment with shareholder objectives. These are shares that vest three years after grant, assuming the employee has not left the Group. They are not eligible for dividends prior to vesting.

The following assumptions were used to estimate the fair value of the restricted shares at the date of grant, discounting back from the date they will vest and excluding the value of dividends during the intervening period:

	Restricted shares granted on	
	22 August 2022	**9 March 2022**
Risk-free rate	1.73%	1.39%
Share price	GB£ 0.90	GB£ 1.01
Expected dividends	1.73%	1.71%

The following table summarises the options/shares under the LTI plans outstanding and exercisable as at 31 December 2023:

			Shares Options			
	Performance shares	**Restricted shares**	**Number of options**	**Weighted average exercise price GB£**	**Weighted average remaining contract life**	**Number of options exercisable**
As at 1 January 2022	1,486,893	151,633	21,166,802	0.45	7.15	11,409,854
New options/share awards issued	1,406,956	293,655	1,030,366	0.92	9.19	-
Vested during the year	-	-	-	0.50	6.27	2,010,007
Accelerated vesting during the year	-	-	-	0.46	6.45	1,354,702
Exercised during the year	-	-	(1,446,108)	0.42	-	(1,446,108)
Cancelled during the year	(147,906)	-	(1,012,124)	0.50	-	(1,012,124)
As at 31 December 2022	**2,745,943**	**445,288**	**19,738,936**	**0.45**	**7.15**	**12,316,331**
Vested during the year	(79,327)	(101,063)	-	0.44	6.32	4,665,000
Exercised during the year	-	-	(128,160)	0.56	-	(128,160)
Expired unexercised during the year	(449,513)	-	-	-	-	-
Cancelled during the year	-	-	(344,655)	0.60	-	(344,655)
As at 31 December 2023	**2,217,103**	**344,225**	**19,266,121**	**0.48**	**5.37**	**16,508,516**

The weighted average share price on the exercise date is GB£0.83 (2022: GB£0.86).

	Number of options	**Range of exercise price GB£**	**Weighted average exercise price GB£**	**Weighted average remaining contract life**
Share options exercisable as at 31 December 2022	12,316,331	0.26 - 0.99	0.41	5.46
Share options exercisable as at 31 December 2023	16,508,516	0.26 - 0.99	0.41	4.92

35. CAPITAL REDEMPTION RESERVE

The capital redemption reserve arose from the Programme launched by the Company in August 2022. It represents the par value of the shares purchased and cancelled by the Company under the Programme (Note 31).

36. HEDGING RESERVE

	2023 USD'000	**2022 USD'000**
At beginning of the year	-	-
Loss arising on changes in fair value of hedging instruments during the year	30,509	-

Income tax related to loss recognised in other comprehensive income	(9,153)	-
Net loss reclassified to profit or loss (Note 4)	(10,322)	-
Income tax related to amounts reclassified to profit or loss	3,097	-
At end of the year	**14,131**	**-**

The hedging reserve represents the cumulative amount of gains and losses on hedging instruments deemed effective in cash flow hedges. The cumulative deferred gain or loss on the hedging instrument is recognised in profit or loss only when the hedged transaction impacts the profit or loss. See Note 42 for further details on the hedging arrangements.

37. PROVISIONS

	Asset restoration obligations (a) USD'000	Contingent payments (b) USD'000	Employees benefits (c) USD'000	Others USD'000	Total USD'000
As at 1 January 2022	404,401	6,179	844	202	411,626
Charged/(Credited) to profit or loss	-	-	122	(202)	(80)
Acquisition of CWLH Assets (Note 19)	64,633	1,940	-	-	66,573
Acquisition of 10% interest in Lemang PSC (Note 20)	337	-	-	-	337
Accretion expense (Note 14)	8,333	-	-	-	8,333
Changes in discount rate assumptions (Note 22)	18,687	-	-	-	18,687
Payment/Utilised	-	-	(81)	-	(81)
Change in provision (Note 10)	-	7,333	-	-	7,333
Fair value adjustment - Lemang PSC (Note 14)	-	349	-	-	349
Fair value adjustment - PenMal Assets (Note 14)	-	1,571	-	-	1,571
Reclassification	-	(3,000)	-	-	(3,000)
As at 31 December 2022 (Restated)*	**496,391**	**14,372**	**885**	**-**	**511,648**
Charged/(Credited) to profit or loss	-	(7,653)	149	1,112	(6,392)
Accretion expense (Note 14)	20,201	-	-	-	20,201
Changes in discount rate assumptions (Notes 12 and 22)	19,420	-	-	-	19,420
Payment/Utilised	(8,589)	-	-	-	(8,589)
Fair value adjustment - Lemang PSC (Note 14)	-	868	-	-	868
Fair value adjustment - CWLH Assets (Note 14)	-	60	-	-	60
Acquisition of 50% interest in PNLP Assets	48,430	-	-	-	48,430
Gross Up (Note 29)	28,176	-	-	-	28,176
Reclassification	(127)	(2,000)	-	-	(2,127)
As at 31 December 2023	**603,902**	**5,647**	**1,034**	**1,112**	**611,695**
As at 31 December 2022					
Current	-	-	703	-	703
Non-current	496,391	14,372	182	-	510,945
	496,391	**14,372**	**885**	**-**	**511,648**
As at 31 December 2023					
Current	102,811	5,000	714	-	108,525
Non-current	501,091	647	320	1,112	503,170
	603,902	**5,647**	**1,034**	**1,112**	**611,695**

*Certain 2022 comparative information has been restated. Please refer to Note 50.

(a) The Group's ARO comprise the future estimated costs to decommission each of the Montara, Stag, Lemang PSC, PenMal Assets and CWLH Assets.

The carrying value of the provision represents the discounted present value of the estimated future costs. Current estimated costs of the ARO for each of the Montara, Stag, Lemang PSC, PenMal Assets and CWLH Assets have been escalated to the estimated date at which the expenditure would be incurred, at an assumed blended inflation rate. The estimates for each asset are a blend of assumed US and respective local inflation rates to reflect the underlying mix of US dollar and respective local dollar denominated expenditures. The present value of the future estimated ARO for each of the Montara, Stag, Lemang PSC, PenMal Assets and CWLH Assets has then been calculated based on a blended risk-free rate. The base estimate ARO for Montara, Stag, Lemang PSC, PenMal Assets and CWLH Assets remains largely unchanged from 2022. The blended inflation rates and risk-free rates used, plus the estimated decommissioning year of each asset are as follows:

No.	Asset	Blended inflation rate 2023	Blended inflation rate 2022	Blended risk-free rate 2023	Blended risk-free rate 2022	Estimated decommissioning year
1.	Montara	2.55%	3.01%	3.99%	3.97%	2031
2.	Stag	2.30%	2.62%	4.08%	4.01%	2036
3.	Lemang PSC	2.24%	2.93%	6.09%	6.43%	2036
4.	PenMal Assets	2.09%	2.46% - 2.48%	3.52% - 3.80%	3.48% - 4.02%	2024 onwards
5.	CWLH Assets	2.58%	3.05%	4.03%	3.94%	2035

Following the enactment of the Offshore Petroleum and Greenhouse Gas Storage Amendment (Titles Administration and Other Measures) Act 2021 which, amongst other things, enhanced the decommissioning framework applying to offshore assets in Australia, on 29 March 2023 Jadestone Energy (Australia) Pty Ltd, Jadestone Energy (Eagle) Pty Ltd and Jadestone Energy (CWLH) Pty Ltd, each wholly owned subsidiaries of the Company, entered into a deed poll with the Australian Government with regard to the requirements of maintaining sufficient financial capacity to ensure that each of Montara's, Stag's and CWLH's asset restoration obligations can be met when due. The deed states that the Group is required to provide financial security in favour of the Australian Government when the aggregate remaining net after-tax cash flow of the Group is below 1.25 times of the Group's estimated decommissioning liabilities net of any residual value, tax benefits, and other financial assurance committed by the Group for such purposes. The Group does not expect to provide financial security under the deed poll this year based on the financial capacity assessment.

The Malaysian and Indonesian regulators require upstream oil and gas companies to contribute to an abandonment cess fund, including making monthly cess payments, throughout the production life of the oil or gas field. The cess payment amount is assessed based on the estimated future decommissioning expenditures. The cess payment paid for non-operated licences reduces the ARO liability. The Malaysian abandonment cess fund only covers the decommissioning costs related to the oil and gas facilities, excluding wells. The Indonesian cess fund covers the decommissioning costs related to all facilities. The Group has recognised ARO provisions for the estimated decommissioning costs of the wells in the PSCs.

An abandonment trust fund was set as part of the acquisition of the CWLH Assets to ensure there are sufficient funds available for decommissioning activities at the end of field life. The cash contribution paid into the trust fund is classified as non-current receivable as the amount is reclaimable by the Group in the future following the commencement of decommissioning activities.

(b) The fair value of the contingent payments payable to Mandala Energy Lemang Pte Ltd for the Lemang PSC acquisition are valued at US5.6 million as at 31 December 2023 (2022: US$12.4 million) for the trigger events as disclosed below. The decrease in provision represents the derecognition of contingent payments associated with the Saudi CP and Dated Brent prices due to the trigger events are not expected to occur based on the specialist's consensus on Dated Brent prices and the historical correlation between Dated Brent prices and Saudi CP.

No.	Trigger event	Consideration	Directors' rationale
1.	First gas date	US$5.0 million	This contingent payment is virtually certain as it will be payable when gas production in the Lemang PSC is commenced.
2.	The accumulated VAT receivables reimbursements which are attributable to the unbilled VAT in the Lemang Block as at the Closing Date, exceeding an aggregate amount of US$6.7 million on a gross basis	US$0.7 million	The Directors estimated that the accumulated receipts of VAT reimbursements received will exceed US$6.7 million on a gross basis.
3.	First gas date on or before 31 March 2023	US$3.0 million	Not payable as the trigger event has expired. First gas is scheduled in first half of 2024.
4.	Total actual Akatara Gas Project "close out" costs set out in the AFE(s) approved pursuant to a joint audit by SKK MIGAS and BPKP is less than, or within 2% of the "close out" development costs set out in the approved revised plan of development for the Akatara Gas Project	US$3.0 million	Based on the status of the Akatara Gas Project as at 2023 year end, the actual "close out" costs set out in the AFE(s) has exceeded the "close out" development costs set out in the approved revised plan by more than 2%. As such, the consideration trigger will not be met.
5.	The average Saudi CP in the first year of operation is higher than US$620/MT	US$3.0 million	The average Saudi CP is not expected to be above US$620/MT in 2024, with the first gas is anticipated to be in H1 2024. The contingent payment will be due for payment within 15 business days of the occurrence of the trigger event if it falls due.
6.	The average Saudi CP in the second year of operation is higher than US$620/MT	US$2.0 million	The average Saudi CP is not expected to be above US$620/MT in 2025, the second year of production. The contingent payment will be due for payment within 15 business days of

No.	Trigger event	Consideration	Directors' rationale
			the occurrence of the trigger event if it falls due.
7.	The average Dated Brent price in the first year of operation is higher than US$80/bbl	US$2.5 million	The average Dated Brent price is not expected to be above US$80/bbl in 2024, with the first gas is anticipated to be in H1 2024. The contingent payment will be due for payment within 15 business days of the occurrence of the trigger event if it falls due.
8.	The average Dated Brent price in the second year of operation is higher than US$80/bbl	US$1.5 million	The average Dated Brent price is not expected to be above US$80/bbl in 2025, the second year of production. The contingent payment will be due for payment within 15 business days of the occurrence of the trigger event if it falls due.
9.	A plan of development for the development of a new discovery made, as a result of the remaining exploration well commitment under the PSC, is approved by the relevant government entity.	US$3.0 million	There are no prospects or leads presently selected for the exploration well commitment. As at year end, it is not probable that this contingent consideration trigger will be met.
10.	The plan of development described in item 9 above is approved by the relevant government entity and is based on reserves of no less than 8.4mm barrels (on a gross basis).	US$8.0 million	There are no prospects or leads presently selected for the exploration well commitment. As at year end, it is not probable that this contingent consideration trigger will be met.

(c) Included in the provision for employee benefits is provision for long service leave which is payable to employees on a pro-rata basis after 7 years of employment and is due in full after 10 years of employment.

38. BORROWINGS

	2023 USD'000	2022 USD'000
Non-current secured borrowings		
Reserve based lending facility	147,313	-
Current secured borrowings		
Reserve based lending facility	7,260	-
	154,573	**-**

On 17 February 2023, the Group closed a US$50.0 million Interim Facility with two international banks to provide additional liquidity prior to closing the RBL facility in support of the acquisition of the Sinphuhorm Assets. In February 2023, US$28.5 million was utilised to fund the acquisition of the Sinphuhorm Assets. A second drawdown of US$21.5 million occurred in May 2023 primarily to fund the US$20.5 million payment into the CWLH abandonment trust fund. The Interim Facility was repaid on 1 June 2023 from the RBL facility obtained by the Group in May 2023. The Group had incurred interest expense of US$1.3 million from the Interim Facility, which was recorded as finance costs in Note 14.

On 19 May 2023, the Group signed a US$200.0 million RBL facility with a group of four international banks ("the RBL Banks"). The facility tenor is four years, with the final maturity date being the earlier of 31 March 2027 and the projected reserves tail[1] (which is expected later). As at 31 December 2023, the borrowing base is secured over the Group's main producing assets being Montara, Stag, CWLH, Sinphuhorm Assets, the PenMal Assets' PM323 and PM329 PSCs and the Group's development asset being the Lemang PSC. The borrowing base as at 31 December 2023 was US$200.0 million. The facility incorporates standard terms and conditions, including a parent company financial covenant for a maximum total debt of 3.5 times annual EBITDAX, tested bi-annually on 30 June and 31 December, and to deliver the required information to the RBL Banks on a timely basis.

The RBL facility pays interest at 450 basis points over the secured overnight financing rate, plus the applicable credit spread. The Group also pays customary arrangement and commitment fees.

As at 31 December 2023, the Group has a net drawdown sum of US$157.0 million. The loan incurred costs of US$7.1 million and the fair value of the loans at drawdown had an amortised carrying value of US$149.9 million. For the year ended 31 December 2023, the Group had incurred interest expense of US$8.1 million and US$0.3 million of commitment fees, which were recorded as finance costs in Note 14.

On 6 June 2023, the Company entered into a committed standby working capital facility with Tyrus Capital Events S.a.r.l.for a facility size of up to US$35.0 million. The standby working capital facility was finalised at US$31.9 million, after deduction of US$3.1 million of excess funds from the total gross funds of US$53.1 million raised from the equity placing and open offer (Note 31). The facility will mature on 31 December 2024. The facility bears interest of 15% on drawn amounts and 5% on undrawn amounts and can be repaid or cancelled without penalties. The standby working capital facility was not utilised during 2023 and remained undrawn as at 31 December 2023. See Note 49 for further details. For the year ended 31 December 2023, the Group had incurred interest expense of US$3.6 million, which was recorded as finance costs in Note 14.

[1] Reserves tail date refers to the last day of the quarter immediately preceding the quarter in which the remaining borrowing base reserves are forecast to be 25 per cent (or less) of the initial approved borrowing base reserves.

39. LEASE LIABILITIES

	2023 USD'000	2022 USD'000
Presented as:		
Non-current	18,746	2,880
Current	14,118	6,227
	32,864	**9,107**
Maturity analysis of lease liabilities based on undiscounted gross cash flows:		
Year 1	17,357	6,649
Year 2	14,662	2,261
Year 3	3,674	426
Year 4	-	334
Year 5	-	-
Future interest charge	(2,829)	(563)
	32,864	**9,107**

The Group does not face a significant liquidity risk with regards to its lease liabilities. Lease liabilities are monitored within the Group's treasury function.

40. RECONCILIATION OF LIABILITIES ARISING FROM FINANCING ACTIVITIES

The table below details changes in the Group's liabilities arising from financing activities, including both cash and non-cash changes. Liabilities arising from financing activities are those for which cash flows were, or future cash flows will be, classified in the Group's consolidated statement of cash flows, as cash flows from financing activities.

The cash flows represent the repayment of borrowings and lease liabilities, in the consolidated statement of cash flows.

	Borrowings USD'000	Lease liabilities USD'000
As at 1 January 2022	-	15,665
Financing cash flows	-	(13,914)
New lease liabilities	-	7,356
Interest paid	-	(769)
Non-cash changes - interest	-	769
As at 31 December 2022	**-**	**9,107**
Financing cash flows	(75,000)	(14,400)
New borrowings	232,000	
New lease liabilities	-	38,157
Borrowings costs paid	(7,595)	-
Interest paid	(5,007)	(2,771)
RBL commitment fees paid	(658)	-
Interest expense	2,571	-
RBL commitment fees	349	-
Non-cash changes - interest	5,518	2,771
Capitalisation of borrowing costs	2,395	-
As at 31 December 2023	**154,573**	**32,864**

41. TRADE AND OTHER PAYABLES

	2023 USD'000	2022 Restated* USD'000
Current		
Trade payables	36,056	13,606
Other payables	9,100	8,643
Accruals	56,534	36,757
Contingent payments	2,000	5,000

Malaysian supplementary payment payables	2,152	855
Amount due to joint arrangement partner	1,252	1,269
Overlift crude oil inventories	6,004	6,957
GST/VAT payables	881	265
	113,979	**73,352**
Non-current		
Other payable	16,917	-
Accrual	49	-
	16,966	**-**
	130,945	**73,352**

Trade payables, other payables and accruals principally comprise amounts outstanding for trade and non-trade related purchases and ongoing costs. The average credit period taken for purchases is 30 days (2022: 30 days). For most suppliers, no interest is charged on the payables in the first 30 days from the date of invoice. Thereafter, interest may be charged on outstanding balances at varying rates of interest. The Group has financial risk management policies in place to ensure that all payables are settled within the pre-agreed credit terms.

The contingent payment in 2023 relates to the final contingent payment payable to BP which arose from the acquisition of the CWLH Assets (Note 19) as the annual average Brent crude price in 2023 exceeded US$60/bbl. The payment was made in January 2024. The contingent payments in 2022 represented the final contingent payment of US$3.0 million payable to SapuraOMV as the annual average Brent crude price in 2022 exceeded US$70/bbl (Note 37). The payment was made in January 2023. In addition, the Group was obliged to pay to a contingent payment of US$2.0 million to BP which arose from the acquisition of the CWLH Assets (Note 19) as the annual average Brent crude price in 2022 exceeded US$50/bbl. The payment was made in January 2023.

The overlift crude oil inventories represent entitlement imbalances at year end of 195,698 bbls at the CWLH Assets (2022: CWLH Assets: 205,510 bbls; PenMal Assets: 31,076 bbls). The overlift liabilities are measured at cost of US$30.68/bbl (2022: CWLH Assets: US$32.92/bbl; PenMal Assets: US$19.07/bbl). The PenMal Assets are in an underlift position as at 2023 year end (Note 29).

The non-current other payable represents future activities which are operational in nature for which cash advances are to be received from the Malaysian joint arrangement partner for its share of future wells preservation activities and decommissioning costs on the PNLP Assets when itwithdrew from the licences in 2023 (Note 29). The Group received the payment in January 2024.

The non-current accrual represents the DCP plan granted during the year as disclosed in Note 34. The DCP has a duration of three years and will be settled by cash on different payout rates at the end of three years subject to the performance of the Group. The performance measures for DCP is similar to the performance shares as disclosed in Note 34.2. The DCP is measured at fair value as at 31 December 2023.

*Certain 2022 comparative information has been restated. Please refer to Note 50.

42. DERIVATIVE FINANCIAL INSTRUMENTS

	2023 USD'000	**2022 USD'000**
Derivative financial liabilities		
Designated as cash flow hedges		
Commodity swap	24,612	-
Measured at fair value though profit or loss		
Foreign exchange forward contracts	73	-
	24,685	**-**
Analysed as:		
Current	17,977	-
Non-current	6,708	-
	24,685	**-**

The following is a summary of the Group's outstanding derivative contracts:

Contract quantity	Type of contracts	Terms	Contract price	Hedge classification	Fair value asset at 31 December 2023 USD'000	Fair value asset at 31 December 2022 USD'000
Contracts designated as cash flow hedges						
50% of Group's planned 2P production	Commodity swap: swap component	Oct 2023 - Sep 2025	Weighted average price of US$70.57/bbl	Cash flow	(24,612)	-
Contracts that are not designated in hedge accounting relationships						
To hedge MYR162.5 million by selling MYR for USD	Foreign exchange forward contracts	Execution date: 2 February 2024	USD/MYR: 4.60	FVTPL	(73)	-

The Group's October 2023 to September 2025 commodity swap programme was designated as a cash flow hedge. Critical terms of the commodity swap (i.e., the notional amount, life and underlying oil price benchmark) and the corresponding Group's hedged sales are highly similar. The Group performed a qualitative assessment of the effectiveness of the commodity swap contracts and concluded that the commodity swap programme is highly effective as the value of the commodity swap and the value of the corresponding hedged items will systematically change in opposite directions in response to movements in the underlying commodity prices.

In August 2023, the Group entered into a foreign exchange forward contract with a bank based in Malaysia to hedge MYR162.5 million (approximately US$35.4 million), being the receivable sum at 2023 year end due from the joint arrangement partner of PNLP Assets for its share offuture decommissioning costs when it exited two PSC licences. The forward contract is to secure the receipts in USD in view of volatility of MYR against USD towards the end of 2023. The forward contract matured on 2 February 2024 following the receipts of the sum from the joint arrangement partner in January 2024.

The following tables detail the commodity swap contracts outstanding at the end of the year, as well as information regarding their related hedged items. Commodity swap contract assets are included in the "derivative financial instruments" line item in the consolidated statement of financial position.

Hedging instruments - outstanding contracts

	Oil volumes bbls	Notional value USD'000	Change in fair value used for calculating hedge ineffectiveness USD'000	Fair value USD'000
2023				
Cash flow hedges				
Commodity swap component	4,531,720	317,629	-	20,187

The following table details the effectiveness of the hedging relationships and the amounts reclassified from hedging reserve to profit or loss:

	Current period hedging (loss)/gain recognised in OCI USD'000	Amount of hedge ineffectiveness recognised in profit or loss USD'000	Line item in profit or loss in which hedge ineffectiveness is included	Amount reclassified to profit or loss due to hedged item affecting profit or loss USD'000	Line item in profit or loss in which reclassification adjustment is included
2023					
Cash flow hedges					
Forecast sales	(20,187)	-	Other expenses	(10,322)	Revenue

43. WARRANTS LIABILITY

On 6 June 2023, in consideration of the support provided to the Company under the equity underwrite debt facility and committed standby working capital facility, the Company entered into a warrant instrument with Tyrus Capital S.A.M. and funds managed by it, for 30 million ordinary shares at an exercise price of 50 pence sterling per share. The warrants are exercisable within 36 months from the date of issuance, with an expiry date of 5 June 2026.

The Directors have applied the Black-Scholes option-pricing model, with the following assumptions, to estimate the fair value of the warrants as at 31 December 2023:

Risk-free rate	3.77%
Expected life	2.5 years

Expected volatility	54.5%
Share price	GB£ 0.37
Exercise price	GB£ 0.50
Expected dividends	0%

[1] Expected volatility was determined by calculating the average historical volatility of the daily share price returns over a period commensurate with the expected life of the awards for a group of ten peer companies.

44. FINANCIAL INSTRUMENTS, FINANCIAL RISKS AND CAPITAL MANAGEMENT

Financial assets and liabilities

Current assets and liabilities

The Directors consider that due to the short-term nature of the Group's current assets and liabilities, the carrying amounts equate to their fair value.

Non-current assets and liabilities

The carrying amount of non-current assets and liabilities approximates their fair values due to the carrying amount representing the actual cash paid.

	2023 USD'000	2022 Restated* USD'000
Financial assets		
At amortised cost		
Trade and other receivables, excluding prepayments, GST/VAT receivables and underlift crude oil inventories	241,179	97,918
Cash and bank balances	153,404	123,329
	394,583	**221,247**
Financial liabilities		
At amortised cost		
Trade and other payables, excluding GST/VAT payables and overlift crude oil inventories	122,060	61,130
Lease liabilities	32,864	9,107
Borrowings	154,573	-
Contingent consideration for Lemang PSC acquisition	5,647	12,432
Contingent consideration for CWLH Assets acquisition	2,000	3,940
Contingent consideration for PenMal Assets acquisition	-	3,000
Derivative financial instruments designated as cash flow hedges	24,612	-
Derivative financial instrument carried at FVTPL	73	-
	341,829	**89,609**

*Certain 2022 comparative information has been restated. Please refer to Note 50.

Fair values are based on the Directors' best estimates, after consideration of current market conditions. The estimates are subjective and involve judgment, and as such may deviate from the amounts that the Group realises in actual market transactions.

Commodity price risk

The Group's earnings are affected by changes in oil prices. As part of the RBL, the Group entered intocommodity swap contracts to hedge 50% of its forecasted production from October 2023 to September 2025 (Note 42).

Commodity price sensitivity

The results of operations and cash flows from oil and gas production can vary significantly with fluctuations in the market prices of oil and/or natural gas. These are affected by factors outside the Group's control, including the market forces of supply and demand, regulatory and political actions of governments, and attempts of international cartels to control or influence prices, among a range of other factors.

The table below summarises the impact on (loss)/profit before tax, and on equity, from changes in commodity prices on the fair value of derivative financial instruments. The analysis is based on the assumption that the crude oil price moves 10%, with all other variables held constant. Reasonably possible movements in commodity prices were determined based on a review of recent historical prices and current economic forecasters' estimates.

Gain or loss	Effect on the result before tax for the year ended 31 December 2023 USD'000	Effect on other comprehensive income before tax for the year ended 31 December 2023 USD'000	Effect on the result before tax for the year ended 31 December 2022 USD'000	Effect on other comprehensive income before tax for the year ended 31 December 2022 USD'000
Increase by 10%	-	(33,861)	-	-
Decrease by 10%	-	33,861	-	-

Foreign currency risk

Foreign currency risk

Foreign currency risk is the risk that a variation in exchange rates between United States Dollars ("US Dollar") and foreign currencies will affect the fair value or future cash flows of the Group's financial assets or liabilities presented in the consolidated statement of financial position as at year end.

Cash and bank balances are generally held in the currency of likely future expenditures to minimise the impact of currency fluctuations. It is the Group's normal practice to hold the majority of funds in US Dollars, in order to match the Group's revenue and expenditures.

In addition to US Dollar, the Group transacts in various currencies, including Australian Dollar, Malaysian Ringgit, Vietnamese Dong, Indonesian Rupiah, Singapore Dollar and British Pound Sterling.

The Group manages its foreign currency risk by monitoring the fluctuations of material foreign currencies against USD and potentially entering into foreign currency forward contract to hedge against the currency fluctuations if and when considered appropriate.

In August 2023, the Group entered into a foreign exchange forward contract with a bank based in Malaysia to hedge MYR162.5 million (approximately US$35.4 million), being the receivable sum at 2023 year end due from the joint arrangement partner of PNLP Assets for its share offuture decommissioning costs when it exited two PSCs' licences. The forward contract was entered to secure the receipts in USD in view of volatility of MYR against USD towards the end of 2023. The forward contract was matured on 2 February 2024 following the receipts of the sum from the joint arrangement partner in January 2024.

Foreign currency sensitivity

Material foreign denominated balances were as follows:

	2023 USD'000	2022 Restated* USD'000
Cash and bank balances		
Australian Dollars	4,777	11,086
Malaysian Ringgit	8,533	5,336
Trade and other receivables		
Australian Dollars	250	1,966
Malaysian Ringgit	42,672	4,269
Trade and other payables		
Australian Dollars	33,250	34,036
Malaysian Ringgit	59,113	12,422

A strengthening/weakening of the Australian dollar and Malaysian Ringgit by 10%, against the functional currency of the Group, is estimated to result in the net carrying amount of Group's financial assets and financial liabilities as at year end decreasing/increasing by approximately US$3.5 million (2022: US$2.4 million), and which would be charged/credited to the consolidated statement of profit or loss.

*Certain 2022 comparative information has been restated. Please refer to Note 50.

Interest rate risk

The Group's interest rate exposure arises from its cash and bank balances, CWLH Assets abandonment trust fund and borrowings. The Group's other financial instruments are non-interest bearing or fixed rate, and are therefore not subject to interest rate risk. The Group continually monitors its cash position and places excess funds into fixed term deposits as necessary.

As at 31 December 2023, the Group held US$82.0 million (2022: US$41.0 million) in the CWLH Assets abandonment trust fund operated by the joint venture operating partner. The abandonment trust funds generates average annual interest rate of 4.5% (2022: 3.6%).

As at 31 December 2023, the Group held US$55.0 million (2022: nil) in fixed term deposits. The fixed term deposits generate average annual interest rate of 4.5% (2022: nil).

On 19 May 2023, the Group signed a US$200.0 million RBL facility with a group of four international banks ("the RBL Banks"). The facility tenor is four years, with the final maturity date being the earlier of 31 March 2027 and the projected reserves tail (which is expected later). The borrowing base is secured over the Group's main producing assets being Montara, Stag, CWLH, Sinphuhorm Assets, the PenMal PM323 and PM329 PSCs and the Group's development asset being the Lemang PSC. The borrowing base as at 31 December 2023 was US$200.0 million.

The RBL facility pays interest at 450 basis points over the secured overnight financing rate, plus the applicable credit spread. The Group also pays customary arrangement and commitment fees.

As at 31 December 2023, the Group has a net drawdown sum of US$157.0 million. The loan incurred costs of US$7.0 million.

Based on the carrying value of the CWLH Assets abandonment trust fund, fixed term deposits and RBL as at 31 December 2023, if interest rates had increased/decreased by 1% and all other variables remained constant, the Group's net loss before tax would be increased/decreased by US$0.1 million (2022: profit before tax increased/decreased by US$0.4 million).

[1] Reserves tail date refers to the last day of the quarter immediately preceding the quarter in which the remaining borrowing base reserves are forecast to be 25 per cent (or less) of the initial approved borrowing base reserves.

Credit risk

Credit risk represents the financial loss that the Group would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms.

The Group actively manages its exposure to credit risk, granting credit limits consistent with the financial strength of the Group's counterparties and respective sole customer in Australia and Malaysia, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures, and close monitoring of relevant accounts.

The Group trades only with recognised, creditworthy third parties.

The Group's current credit risk grading framework comprises the following categories:

Category	Description	Basis for recognising expected credit losses ("ECL")
Performing	The counterparty has a low risk of default and does not have any past due amounts.	12-month ECL
Doubtful	Amount is > 30 days past due or there has been a significant increase in credit risk since initial recognition.	Lifetime ECL - not credit-impaired
In default	Amount is > 90 days past due or there is evidence indicating the asset is credit-impaired.	Lifetime ECL - credit-impaired
Write-off	There is evidence indicating that the debtor is in severe financial difficulty and the Group has no realistic prospect of recovery.	Amount is written off

The table below details the credit quality of the Group's financial assets and other items, as well as maximum exposure to credit risk by credit risk rating grades:

	Note	External credit rating	Internal credit rating	12-month ("12m") or lifetime ECL	Gross carrying amount (i) Reclassified* USD'000	Loss allowance USD'000	Net carrying amount Reclassified* USD'000
2023							
Cash and bank balances	30	n.a	Performing	12m ECL	153,404	-**	153,404
Trade receivables	29	A2	(i)	Lifetime ECL	12,533	-**	12,533
Other receivables and deposits	29	n.a	(i)	12m ECL	88,005	-**	88,005
Amount due from joint arrangement partners (net)	29	n.a	(i)	12m ECL	12,911	-**	12,911
Non-current other receivables	29	n.a	(i)	12m ECL	127,730	-**	127,730
2022 (Reclassified)*							
Cash and bank balances	30	n.a	Performing	12m ECL	123,329	-**	123,329
Trade receivables	29	A2	(i)	Lifetime ECL	6,332	-**	6,332
Other receivables	29	n.a	(i)	12m ECL	4,126	-**	4,126
Amount due from joint arrangement partners (net)	29	n.a	(i)	12m ECL	4,268	-**	4,268
Non-current other receivables	29	n.a	(i)	12m ECL	83,192	-**	83,192

** The amount is negligible.

(i) For trade receivables, the Group has applied the simplified approach in IFRS 9 to measure the loss allowance at lifetime ECL. The Group determines the expected credit losses on these items by using specific identification, estimated based on historical credit loss experience based on the past due status of the debtors, adjusted as appropriate to reflect current conditions and estimates of future economic conditions. Accordingly, the credit risk profile of these assets is presented based on their past due status in terms of specific identification.

As at 31 December 2023, total trade receivables amounted to US$12.5 million (2022: US$6.3 million). The balance in 2023 and 2022 had been fully recovered in 2024 and 2023, respectively.

The concentration of credit risk relates to the Group's single customer with respect to oil sales in Australia, and a different single customer for oil and gas sales in Malaysia. Both customers have an A2 credit rating (Moody's). All trade receivables are generally settled 30 days after sale date. In the event that an invoice is issued on a provisional basis, the final reconciliation is paid within 3 to 14 days from the issuance of the final invoice, largely mitigating any credit risk.

The Group recognises lifetime ECL for trade receivables. The ECL on these financial assets are estimated based on days past due, by applying a percentage of expected non-recoveries for each group of receivables. As at year end, ECL from trade receivables are expected to be insignificant.

The Group measures the loss allowance for other receivables and amount due from joint arrangement partners at an amount equal to 12-months ECL, as there is no significant increase in credit risk since initial recognition. ECL for other receivables are expected to be insignificant.

The credit risk on cash and bank balances and CWLH trust fund is limited because counterparties are banks with high credit ratings assigned by international credit rating agencies.

The maximum credit risk exposure relating to financial assets is represented by their carrying value as at the reporting date.

*Certain 2022 comparative information has been reclassified between line items. Please refer to Note 50.

Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet all of its financial obligations as they become due. This includes the risk that the Group cannot generate sufficient cash flow from producing assets, or is unable to raise further capital in order to meet its obligations.

The Group manages its liquidity risk by optimising the positive free cash flow from its producing assets, on-going cost reduction initiatives, merger and acquisition strategies, bank balances on hand and in case appropriate, lending.

The Group's net loss after tax for the year was US$91.3 million (2022: profit after tax of US$9.2 million). Operating cash flows before movements in working capital and net cash used in operating activities for the year ended 31 December 2023 was US$36.5 million and US$12.1 million (2022: US$158.5 million and net cash generated of US$121.2 million) respectively. The Group's net current asset remained positive at US$37.9 million as at 31 December 2023 (2022: US$72.4 million).

On 19 May 2023, the Group signed a US$200.0 million RBL facility with a group of four international banks ("the RBL Banks"). The facility tenor is four years, with the final maturity date being the earlier of 31 March 2027 and the projected reserves tail (which is expected later). The borrowing base is secured over the Group's main producing assets being Montara, Stag, CWLH, Sinphuhorm Assets, the PenMal Assets' PM323 and PM329 PSCs and the Group's development asset being the Lemang PSC. The borrowing base as at 31 December 2023 was US$200.0 million.

The Group is required to maintain a parent company financial covenant of consolidated net debt below 3.5 times annual EBITDAX and to deliver the required information to the RBL Banks on a timely basis. As at 31 December 2023, the Company's financial covenant was 0.14.

The RBL imposes restrictions on the ability of the Group to freely utilise the cashflows generated by the borrowing base assets for purposes that are not connected with the borrowing base assets or the RBL. It is therefore necessary of the Group to maintain two separate cash pools, a) cash balances within the RBL facility ("RBL Cash Pool") and b) cash balances outside the RBL facility, which comprise cash held by the entities that are not part of the RBL facility including the corporate G&A, Malaysia Technical Office and Singapore, the Vietnamese exploration assets and the previously non-operated PenMal Assets (PM318 and AAKBNLP PSCs) ("Corporate Cash Pool"). The distribution of cash out of the RBL Cash Pool is allowed provided that certain tests are met, such as (i) the maintenance of two quarters principal, interest and fees in a separate debt service reserve account and (ii) the maintenance of the minimum cash balance within the RBL Cash Pool.

On 6 June 2023, the Company completed an equity fundraising, creating an additional 94,081,826 ordinary shares at GB£0.45 per share, which comprised of a placing and subscription of 92,312,691 new ordinary shares to existing and new institutional shareholders and a placing and subscription of 1,769,135 new ordinary shares to the Directors of the Company. Total gross proceeds were US$53.1 million, with net proceeds of US$51.1 million.

On 9 June 2023, the Company launched an open offer of up to 14,887,039 new ordinary shares, at GB£0.45 per share, to raise additional proceeds of up to EUR8.0 million[2] (up to US$8.6 million). The open offer closed on 28 June 2023, raising a total of US$42,009 by issuing 73,557 new shares.

In support of the equity fundraising, the Company entered into an up to US$50.0 million equity underwrite debt facility agreement with Tyrus. The equity underwrite facility was reduced to zero as funds raised from the equity fundraising exceeded US$50.0 million.

In addition, the Company entered into a committed standby working capital facility with Tyrus for a facility size of up to US$35.0 million. The standby working capital facility was finalised at US$31.9 million, after deduction of US$3.1 million, being the amount in excess of US$50.0 million, following a total gross funds of US$53.1 million raised from the equity placing and open offer. The facility will mature with a bullet repayment on 31 December 2024. The facility bears interest of 15% on drawn amounts and 5% on undrawn amounts and can be repaid or cancelled without penalties. The standby working capital facility was undrawn as at 31 December 2023.

Further details are disclosed in the Going Concern section in Note 2.

[1] Reserves tail date refers to the last day of the quarter immediately preceding the quarter in which the remaining borrowing base reserves are forecast to be 25 per cent (or less) of the initial approved borrowing base reserves.

[2] The open offer was quoted in Euro of 8.0 million to meet the applicable regulation issued by the European Union regarding to the quantum of open offer.

Derivative and non-derivative financial liabilities

The following table details the expected contractual maturity for derivative and non-derivative financial liabilities with agreed repayment periods. The table below is based on the undiscounted contractual maturities of the financial liabilities, including interest, that will be paid on those liabilities, except where the Group anticipates that the cash flow will occur in a different period.

	Weighted average effective interest rate %	On demand or within 1 year USD'000	Wit U
2023			
Non-interest bearing			
Trade and other payables, excluding contingent payments, GST/VAT payables and overlift crude oil inventories	-	105,094	
Contingent consideration for Lemang PSC acquisition	-	5,000	
Contingent consideration for CWLH Assets acquisition	-	2,000	
Derivative financial instruments designated as cash flow hedges	-	17,904	
Derivative financial instrument carried at FVTPL	-	73	
Fixed interest rate Instrument			
Lease liabilities	9.660	14,118	
Variable interest rate instrument			
Borrowings	11.084	7,260	
		151,449	
2022			
Non-interest bearing			
Trade and other payables, excluding contingent payments, GST/VAT payables and overlift crude oil inventories	-	61,130	
Contingent consideration for Lemang PSC acquisition	-	-	
Contingent consideration for CWLH Assets acquisition	-	2,000	
Contingent consideration for PenMal Assets acquisition	-	3,000	
Fixed interest rate instruments			
Lease liabilities	6.031	6,227	
		72,357	

Non-derivative financial assets

The following table details the expected maturity for non-derivative financial assets. The inclusion of information on non-derivative financial assets assists in understanding the Group's liquidity position and phasing of net assets and liabilities, as the Group's liquidity risk is managed on a net asset and liability basis. The table is based on the undiscounted contractual maturities of the financial assets, including interest that will be earned on those assets, except where the Group anticipates that the cash flow will occur in a different period.

	Weighted average effective interest rate %	On demand or within 1 year Reclassified* USD'000	Within 2 to 5 years USD'000	More than 5 years USD'000	Total Reclassified* USD'000
2023					
Non-interest bearing					
Trade and other receivables, excluding prepayments, GST/VAT receivables and underlift crude oil inventories	-	113,449	127,730	-	241,179
Variable interest rate instruments					
Cash and bank balances	-(a)	152,396	1,008	-	153,404
		265,845	**128,738**	**-**	**394,583**
2022 (Reclassified)*					
Non-interest bearing					
Trade and other receivables, excluding prepayments, GST/VAT receivables and underlift crude oil inventories	-	14,726	83,192	-	97,918
Variable interest rate instruments					
Cash and bank balances	-(a)	122,653	676	-	123,329
		137,379	**83,868**	**-**	**221,247**

(a) The effect of interest is not material.

* Certain 2022 comparative information has been reclassified between line items. Please refer to Note 50.

Capital management

The Group manages its capital structure and makes adjustments to it, based on funding requirements of the Group combined with sources of funding available to the Group, in order to support the acquisition, exploration and development of resource properties and the ongoing (investment in) operations of its producing assets. Given the nature of the Group's activities, the Board of Directors works with management to ensure that capital is managed effectively, and the business has a sustainable future.

The capital structure of the Group represents the equity of the Group, comprising share capital, merger reserve, share-based payment reserve, capital redemption reserve and hedging reserve, as disclosed in Notes 31, 33, 34, 35 and 36, respectively.

To carry-out planned asset acquisitions, exploration and development, and to pay for administrative costs, the Group may utilise excess cash generated from its ongoing operations and may utilise its existing working capital, position and will work to raise additional debt and/or equity funding should that be necessary.

The Directors review its capital management approach on an ongoing basis and believes that this approach, given the relative size of the Group, is reasonable. There were no changes in the Group's approach to capital management during the year ended 31 December 2023. The Group is not subject to externally imposed capital requirements.

	2023 USD'000	2022 USD'000
Gearing ratio		
Borrowings	154,573[1]	-
Cash and cash equivalents	(153,404)	(123,329)
Net debt/(cash)	**1,169**	**(123,329)**
Equity	53,770	109,529
Net debt to equity ratio	**2%**	**N/M**

The Group's overall strategy towards its capital structure remained unchanged from 2022.

[1] The borrowings of US$154.6 million represents the fair value of the balance. The gross outstanding balance as at 31 December 2023 is US$157.0 million, which generates a net debt to equity ratio of 7%.

Fair value measurements

The Group discloses fair value measurements by level of the following fair value measurement hierarchy:

i. Quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1);

ii. Inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly (Level 2); and

iii. Inputs for the asset or liability that are not based on observable market data (unobservable inputs) (Level 3).

Financial assets/financial liabilities	Fair value (USD'000) as at 2023 Assets	2023 Liabilities	2022 Assets	2022 Liabilities	Fair value hierarchy	Valuation technique(s) and key input(s)	unobs
Derivative financial instruments							
1) Commodity swap contracts (Note 42)	-	24,612	-	-	Level 2	Third party valuations based on market comparable information.	-
2) Foreign forward contracts (Note 42)	-	73	-	-	Level 2	Third party valuations based on market comparable information.	-
Others - contingent consideration from Lemang PSC acquisition							
3) Contingent consideration (Note 37)	-	5,647	-	12,432	Levels 1 and 3	Based on the nature and the likelihood of the occurrence of the trigger events. Fair value is estimated, taking into consideration the estimated future gas production schedule (H1 2024), forecasted Dated Brent oil prices of US$76.00/bbl in 2024 and US$74.45/bbl in 2025 and Saudi CP prices of US$615.98/MT in 2024 and US$603.42/MT in 2025, estimated future recoverability	Gas proc could b depend going p develop activiti Expected price vc on an a Dated B and Sau movem

estimated future recoverability of VAT receivables as well as the effect of the time value of money.

A one year deferral to the estimated gas production date would decrease the liability by US$0.7 million. A 10% increase/decrease in th recognition of the Lemang contingent payment associated with the future reimbursements of VAT receivables.

Financial assets/financial liabilities	Fair value (USD'000) as at 2023 Assets	2023 Liabilities	2022 Assets	2022 Liabilities	Fair value hierarchy	Valuation technique(s) and key input(s)	unobs
Others - contingent consideration from CWLH Assets acquisition							
4) Contingent consideration (Notes 19, 37 and 41)	-	2,000	-	3,940	Level 1	Based on the actual average Dated Brent prices in 2023 of US$82.64/bbl.	-
Others - contingent consideration from PenMal Assets acquisition							
5) Contingent consideration (Note 41)	-	-	-	3,000	Level 1	Based on the actual average Dated Brent prices in 2022 of US$101.32/bbl.	-

45. SEGMENT INFORMATION

Information reported to the Group's Chief Executive Officer (the chief operating decision maker) for the purposes of resource allocation is focused on two reportable/business segments driven by different types of activities within the upstream oil and gas value chain, namely producing assets and secondly development and exploration assets. The geographic focus of the business is on Southeast Asia ("SEA") and Australia.

Revenue and non-current assets information based on the geographical location of assets respectively are as follows:

	Producing assets Australia USD'000	Producing assets SEA USD'000	Exploration/ development SEA USD'000	Corporate USD'000	Total USD'000
2023					
Revenue					
Liquids revenue	240,630	66,517	-	-	307,147
Gas revenue	-	2,053	-	-	2,053
	240,630	**68,570**	**-**	**-**	**309,200**
Production cost	(185,039)	(47,733)	-	-	(232,772)
DD&A	(65,204)	(10,397)	(248)	(292)	(76,141)
Administrative staff costs	(14,550)	(5,060)	(1,773)	(8,814)	(30,197)
Other expenses	(12,652)	(3,363)	(2,319)	(4,507)	(22,841)
Impairment of assets	(17,410)	(12,271)	-	-	(29,681)
Share of results of associate	-	2,640	-	-	2,640
Other income	9,990	192	7,684	989	18,855
Finance costs	(22,611)	(6,565)	(2,274)	(10,379)	(41,829)
Profit/(Loss) before tax	**(66,846)**	**(13,987)**	**1,070**	**(23,003)**	**(102,766)**
Additions to non-current assets	86,403	54,576	90,611	703	232,293
Non-current assets	346,281	191,550	209,373	642	747,846
2022 (Restated)*					
Revenue					
Liquids revenue	328,863	89,620	-	-	418,483
Gas revenue	-	3,119	-	-	3,119

	328,863	**92,739**	**-**	**-**	**421,602**
Production cost	(188,641)	(61,659)	-	-	(250,300)
DD&A	(57,563)	(3,405)	(235)	(359)	(61,562)
Administrative staff costs	(13,839)	(4,073)	(2,020)	(9,286)	(29,218)
Other expenses	(8,872)	(1,877)	(8,188)	(3,368)	(22,305)
Impairment	-	(13,534)	-	-	(13,534)
Other income	24,226	2,718	965	124	28,033
Finance costs	(6,717)	(2,033)	(903)	(1,774)	(11,427)
Other financial gains	1,904	-	-	-	1,904
Profit/(Loss) before tax	**79,361**	**8,876**	**(10,381)**	**(14,663)**	**63,193**
Additions to non-current assets	110,405	582	23,266	69	134,322
Non-current assets	400,894	101,835	115,390	231	618,350

*Certain 2022 comparative information has been restated. Please refer to Note 50.

Non-current assets as shown here comprises oil and gas properties, intangible exploration assets, right-of-use assets, other receivables and prepayment and plant and equipment used in corporate offices. Deferred tax assets are excluded from the segmental note but included in the Group's consolidated statement of financial position.

Revenue arising from producing assets relates to the Group's single customer with respect to oil sales in Australia, and a different single customer for oil and gas sales in Malaysia. There is an active market for the Group's oil and gas so they can be sold to other buyers, if required.

46. FINANCIAL CAPITAL COMMITMENTS

Certain PSCs and service concessions have firm capital commitments. The Group has the following outstanding minimum commitments:

SEA portfolio PSC operational commitments

	2023 USD'000	2022 USD'000
Not later than one year	10,400	400
One to five years	9,284	19,284
More than 5 years	2,619	3,016
	22,303	**22,700**

The SEA portfolio PSC operational commitments as at 31 December 2023 amounted to US$17.3 million (2022: US$ 17.3 million), and relates to the minimum work commitment outstanding for the Block 46/07 PSC and the Lemang PSC. The operational commitments also include training commitment of US$5.0 million (2022: US$5.4 million), for the Block 46/07 PSC, Block 51 PSC and the PenMal Assets.

<u>Work commitment</u>

Under the terms of the Block 46/07 PSC, Jadestone is committed to drill one more appraisal well on the block. The Group plans to drill an appraisal well on the Nam Du field to facilitate transition of 3C resource to 2C status. This well would be retained for future use as a Nam Du gas producer. The current exploration phase expires on 29 June 2024. On 25 January 2024, the Group signed a gas sales heads of agreement ("HoA") with Petrovietnam Gas Joint Stock Corporation ('PV Gas'). The HoA enables the submission of an updated Nam Du/U Minh Field Development Plan for approval, which is required before a final investment decision and commercialisation of this potential resource. The Group has submitted a request to Petrovietnam to extend the drilling deadline to align the timing of the commitment well with the Nam Du/U Minh project schedule.

As part of the acquisition under the terms of the Lemang PSC, the Group, as the operator, has inherited unfulfilled work commitments of US$7.3 million (2022: US$7.3 million) consisting of one exploration well and a 3D seismic programme. The work commitments should have been completed during the exploration phase of the PSC by the previous owner. It has been agreed with the Indonesian regulator that the work commitments can be completed after first gas in 2024 but before the end of 2026.

<u>Training commitment</u>

Under the terms of the Block 46/07 PSC and Block 51 PSC, the Group commits to pay an annual training commitment amount of US$0.4 million to Petrovietnam until the expiration of the respective PSC licence. The training commitment amount is for the purpose of developing the local employees in the oil and gas industry.

As part of the acquisition under the terms of the PenMal Assets, the Group has inherited net training commitments of US$0.3 million and US$0.1 million for PM323 PSC and PM318 PSC, respectively. Funds provided with respect to this training commitment are applied to the development of local employees in the oil and gas industry. The training commitments are required to be completed before the expiration of the respective PSC.

Capital commitments

The Group has the following capital commitments for expenditure that were contracted for at the end of the reporting year but not recognised as liabilities:

	2023 USD'000	2022 USD'000
Not later than one year	28,489	67,487
One to five years	2,570	9,147
	31,059	**76,634**

The capital commitments of US$31.1 million as at 2023 year end predominately arose from the Lemang PSC's engineering, procurement, construction and installation ("EPCI") contract awarded to design and build the gas processing facility. The project at the year end was approximately 91% complete with first gas scheduled for the first half of 2024. The gross contractual amount under the EPCI contract was US$99.9 million. The Group is expected to spend US$26.7 million in 2024.

The Group also contracted for US$1.2 million which is associated with Stag drilling campaign being deferred to 2024 and US$0.5 million for phase 2 subsea control system upgrade and Skua-11 satellite communication system upgrade at Montara. In 2022, the Group contracted for US$0.3 million which was associated with the installation of produced water treatment unit and phase 1 subsea control system upgrade at Montara.

47. CONTINGENT LIABILITIES

Montara Venture FPSO investigation

On 17 June 2022, a loss of containment of between three and five cubic metres of oil occurred at the Montara Venture FPSO. The facility was shut-in immediately and the incident was reported to the local regulator. The local regulator has commenced an investigation into the incident for potential breach of the local regulations. The investigation is ongoing as at year end and is anticipated to continue throughout 2024. It is too early to reliably estimate the outcome of the investigation and if any prosecution will eventuate.

48. EVENTS AFTER THE END OF THE REPORTING PERIOD

Acquisition of additional interest in the CWLH oil fields

On 14 November 2023, the Group has executed a sale and purchase agreement with Japan Australia LNG (MIMI) Pty Ltd (the "Seller"), to acquire the Seller's non-operated 16.67% working interest in the Cossack, Wanaea, Lambert, and Hermes ("CWLH") oil fields development, offshore Western Australia, for a total initial cash consideration of US$9.0 million, and certain subsequent Abandonment Trust Payments (the "Acquisition").

The Acquisition was completed on 14 February 2024, with a net receipt to the Group from the Seller of US$6.3 million, reflecting the accumulated economic benefits of the CWLH assets for the period from the effective date of 1 July 2022 to completion. As a result, the Group's non-operated working interest in the CWLH assets increased to 33.33%, from 16.67%.

Redetermination of the borrowing base under the reserves-based lending facility

On 26 April 2024, the RBL Banks finalised a routine redetermination of the borrowing base under the RBL, with the revised borrowing capacity of US$200.0 million. Stag has been removed from the borrowing base assets and replaced with the second acquisition of 16.67% of the CWLH assets, acquired on 14 February 2024. The next scheduled redetermination is scheduled to complete by 30 September 2024.

Suspension and restoration of trading on AIM

On 13 February 2024, the ordinary shares of the Company were suspended from trading pursuant to a proposed sale by Woodside Energy Group Ltd. ("Woodside") of its participating interests in the Macedon and Greater Pyrenees Projects offshore Western Australia (the "Proposed Acquisition"). Had Jadestone been selected as the preferred bidder and reached agreement with Woodside on acquisition terms, the Proposed Acquisition would have been classified as a reverse takeover transaction in accordance with AIM Rule 14, and accordingly, the Company's ordinary shares were suspended from trading on AIM on 13 February 2024. On 11 April 2024, Woodside cancelled the sale of its participating interests in those assets. With the possibility of the Proposed Acquisition ceasing, the Company's shares resumed trading on AIM on 11 April 2024.

Change in Board of Directors

On 25 January 2024, the Company announced the appointment of Joanne Williams as an independent non-executive director. Ms. Williams is Chair of both the HSEC Committee and the Montara Technical Committee, and a member of the Audit Committee.

On 25 March 2024, the Company announced the appointment of Adel Chaouch as an independent non-executive director. On the same day, the Company announced the resignation of (i) Lisa Stewart as an independent non-executive director and (ii) Robert Lambert as an independent non-executive director.

On 27 March 2024, the Company announced the resignation of Dennis McShane as an independent non-executive director and Chair of the Board. On the same day, the Company announced the election of Adel Chaouch as Chair of the Board. Mr. Chaouch is Chair of the Governance and Nomination Committee, and a member of both the Remuneration Committee and the HSEC Committee.

49. RELATED PARTY TRANSACTIONS

Placement of additional shares and issue of warrants

On 6 June 2023, the Company completed an equity fundraising, creating an additional 94,081,826 ordinary shares at GB£0.45 per share, which comprised of a placing and subscription of 92,312,691 new ordinary shares to existing and new institutional shareholders and a placing and subscription of 1,769,135 new ordinary shares to the Directors of the Company. Tyrus has subscribed to 24,883,387 of new ordinary shares under the equity fundraising for a consideration of US$13.9 million.

The placing and subscription of 1,769,135 new ordinary shares to the Directors of the Company as follows:

	Number of shares	Consideration paid USD'000
A. Paul Blakeley	336,311	188
Bert-Jaap Dijkstra	71,556	40
Dennis McShane	178,889	100
Iain McLaren	22,222	12
Robert Lambert	111,269	62
Cedric Fontenit	333,333	186
Lisa Stewart	178,889	100
David Neuhauser	447,222	250
Jenifer Thien	89,444	50
	1,769,135	**988**

In support of the equity fundraising, the Company has entered into an up to US$50.0 million equity underwrite debt facility agreement with Tyrus. The equity underwrite facility reduced to zero following the total funds raised from the equity fundraising and the open offer exceeded US$50.0 million. The Group incurred upfront fee of US$2.15 million and interest of US$27,778 from the equity underwrite facility, which was recorded as finance costs in Note 14.

As part of the underwritten placing of additional ordinary shares, the Company has also entered into a warrant instrument with Tyrus for 30 million ordinary shares at an exercise price of 50 pence per share. The warrants are exercisable within 36 months from the date of issuance, with an expiry date of 5 June 2026.

Committed standby working capital facility

On 6 June 2023, the Company entered into a committed standby working capital facility with Tyrus for a facility size of up to US$35.0 million. The standby working capital facility was finalised at US$31.9 million, after deduction of US$3.1 million of excess funds from the total gross funds of US$53.1 million raised from the equity placing and open offer. The facility will mature on 31 December 2024. The facility bears interest of 15% on drawn amounts and 5% on undrawn amounts and can be repaid or cancelled without penalties. The standby working capital facility was not utilised during 2023 and remained undrawn as at 31 December 2023. For the year ended 31 December 2023, the Group had incurred interest expense of US$3.6 million, which was recorded as finance costs in Note 14.

Compensation of key management personnel

	2023 USD'000	2022 USD'000
Short-term benefits	7,934	7,492
Other benefits	566	2,029
Share-based payments	556	810
	9,056	**10,331**

The total remuneration of key management members in 2023 (including salaries and benefits) was US$9.1 million (2022: US$10.3 million) and recognised as part of the Group's administrative staff costs as disclosed in Note 7.

Compensation of Directors

	Short-term benefits[(a)] USD'000	Other benefits[(a)] USD'000	Share-based payments USD'000	Total compensation USD'000
2023				
A. Paul Blakeley	1,093	-	210	1,303
Bert-Jaap Dijkstra	785	-	84	869
Dennis McShane	155	-	1	156
Iain McLaren	105	-	1	106
Robert Lambert	95	-	1	96
Cedric Fontenit	85	-	1	86
Lisa Stewart	100	-	1	101
David Neuhauser	80	-	1	81
Jenifer Thien	100	-	-	100
Gunter Waldner[(b)]	-	-	-	-
	2,598	**-**	**300**	**2,898**
2022				
A. Paul Blakeley	1,236	-	271	1,507
Bert-Jaap Dijkstra	268	23	35	326
Dennis McShane	155	-	6	161
Iain McLaren	105	-	4	109

Robert Lambert	95	-	4	99
Cedric Fontenit	90	-	4	94
Lisa Stewart	100	-	13	113
David Neuhauser	80	-	4	84
Jenifer Thien	71	-	-	71
Daniel Young	229	353	-	582
	2,429	**376**	**341**	**3,146**

(a) Short-term benefits comprise salary, director fee as applicable, performance pay, pension and other allowances. Other benefits comprise benefits-in-kind.

(b) Mr. Waldner was appointed as the Non-Executive Director of the Company as a direct obligation under a 2018 Relationship Agreement between Tyrus and the Company. Both parties agreed that Mr. Waldner will not receive director fee but is reimbursable for reasonable and documented expenses incurred in performing the Non-Executive Director duties.

50. RESTATEMENT AND RECLASSIFICATION OF COMPARATIVE FIGURES

Certain comparative figures in the consolidated financial statements of the Group have been restated arising from a change in accounting policy as well as reclassifications to conform to the presentation in the current year and to better reflect the nature of the respective items in the Group's consolidated financial statements.

As disclosed in Note 2, the prior year restatements were made following the adoption of Amendments to IAS 12*Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction*in 2023 which require the deferred tax assets and deferred tax liabilities to be presented separately in the balance sheet rather than offsetting against each other with additional exclusions have been added to the initial recognition exemption by the IASB. The adoption of Amendments to IAS 12 has impacted the Group's recognition of deferred tax assets and liabilities associated with the oil and gas properties and ARO provision. The restatements were also required to be made on the beginning of the preceding period as at 1 January 2022. The restatements had resulted to an increase in the accumulated losses and deferred tax liabilities by US$13.9 million and reduced the net assets as at 1 January 2022 by US$13.9 million. The third consolidated statement of financial position as at the beginning of the preceding period is not presented due to the restatements do not materially impact the information in the consolidated statement of financial position at the beginning of the preceding period.

Additionally, the finalisation of the PPA for the acquisition of the CWLH Assets in accordance with IFRS 3 (Note 19) generated associated impacts to the oil and gas properties, accumulated losses, ARO provision and overlift balances. The adjustments to the PPA values of the CWLH Assets' oil and gas properties and ARO provision on the acquisition date of 1 November 2022 resulted to the adjustment to the depletion charges and ARO accretion expense recognised in 2022 subsequent to the acquisition in the consolidated statement of profit or loss.

	As previously reported USD'000	Restatements USD'000	As restated USD'000
Consolidated statement of profit or loss and other comprehensive income for the year ended 31 December 2022			
Production costs	(250,700)	400	(250,300)
Depletion, depreciation and amortisation	(61,834)	272	(61,562)
Finance costs	(11,408)	(19)	(11,427)
Income tax expense	(54,018)	62	(53,956)
Consolidated statement of financial position as at 31 December 2022			
Oil and gas properties	456,768	(23,123)	433,645
Deferred tax assets	9,118	13,725	22,843
Accumulated losses	(51,787)	(13,204)	(64,991)
Provisions - non-current	508,539	2,406	510,945
Deferred tax liabilities	88,406	1,800	90,206
Trade and other payables	73,752	(400)	73,352
Consolidated statement of financial position as at 1 January 2022			
Deferred tax assets	26,389	(2,523)	23,866
Accumulated losses	(35,023)	(13,919)	(48,942)
Deferred tax liabilities	(66,166)	(11,396)	(77,562)
Consolidated statement of cash flows for the year ended 31 December 2022			
Profit before tax	62,540	653	63,193
Depletion, depreciation and amortisation	61,834	(272)	61,562
Decrease in trade and other payables	(2,471)	(400)	(2,871)

The reclassification made in the consolidated statement of financial position is related to inventories in transit which are reclassified from trade and other receivables to inventories. The reclassification does not have impact on the net assets balance in the consolidated statement of financial position and consolidated statement or profit or loss and other comprehensive income.

The reclassification impacts the following items:

	As previously reported USD'000	Reclassification USD'000	As reclassified USD'000
Consolidated statement of financial position as at 31 December 2022			
Inventories	18,911	733	19,644
Trade and other receivables	20,368	(733)	19,635
Consolidated statement of cash flows for the year ended 31 December 2022			
(Increase)/Decrease in trade and other receivables	(214)	733	519
Increase in inventories	(1,096)	(733)	(1,829)

As a result of the finalisation of the PPA for the acquisition of the CWLH Assets during the year in accordance with IFRS 3, certain line items have been amended in the statement of financial position and related notes to the financial statements.

The items were adjusted as follows:

	Provisional PPA USD'000	Adjustments USD'000	Final PPA USD'000
Oil and gas properties	41,976	(21,307)	20,669
Deferred tax assets	-	19,390	19,390
Provision for asset restoration obligations	60,158	4,475	64,633
Deferred tax liabilities	12,593	(6,392)	6,201

Company Statement of Financial Position as at 31 December 2023

	Notes	2023 USD'000	2022 USD'000
Assets			
Non-current assets			
Investment in subsidiaries	5	27,598	26,838
Loan to a subsidiary	7	217,112	252,485
Total non-current asset		**244,710**	**279,323**
Current assets			
Amount owing by subsidiaries		105,875	32,521
Prepayments		1,910	20
Cash and cash equivalents		56,588	18,814
Total current assets		**164,373**	**51,355**
Total assets		**409,083**	**330,678**
Equity and liabilities			
Equity			
Capital and reserves			
Share capital	8	456	339
Share premium account	8	51,827	983
Merger reserve		61,068	61,068
Share-based payment reserve	10	27,673	26,907
Capital redemption reserve		24	21
Retained earnings		235,842	232,984
Total equity		**376,890**	**322,302**
Liabilities			
Current liabilities			
Other payables and accruals	11	1,455	851
Amount owing to a subsidiary		27,269	7,525
Warrant liability	12	3,469	-

Total current liabilities	**32,193**	**8,376**
Total liabilities	**32,193**	**8,376**
Total equity and liabilities	**409,083**	**343,563**

During the year, the Company made a profit after tax of US$4.9 million (2022: US$48.1 million loss after tax).

Company Statement of Changes in Equity for the year ended 31 December 2023

	Share capital USD'000	**Share premium account USD'000**	**Capital redemption reserve USD'000**	**Share-based payments reserve USD'000**
As at 1 January 2022	358	201	-	25,936
Share-based compensation:				
Company	-	-	-	38
Subsidiaries	-	-	-	933
Dividend paid (Note 9)	-	-	-	-
Shares issued (Note 8)	2	782	-	-
Shares repurchased (Note 8)	(21)	-	21	-
Total transactions with owners	**(19)**	**782**	**21**	**971**
Loss and total comprehensive income for the year	-	-	-	-
As at 31 December 2022	**339**	**983**	**21**	**26,907**
Share-based compensation:				
Company	-	-	-	6
Subsidiaries	-	-	-	760
Shares issued (Note 8)	120	52,846	-	-
Transaction costs associated with issuance of shares (Note 31)	-	(2,002)	-	-
Shares repurchased (Note 8)	(3)	-	3	-
Total transactions with owners	**117**	**50,844**	**3**	**766**
Profit and total comprehensive income for the year	**-**	-	**-**	-
As at 31 December 2023	**456**	**51,827**	**24**	**27,673**

Company Notes to the Financial Statements for the year ended 31 December 2023

1. CORPORATE INFORMATION

The Company is incorporated and registered in England and Wales. The Company's head office is located at 3 Anson Road, #13-01 Springleaf Tower, Singapore 079909. The registered office of the Company 6th Floor, 60 Gracechurch Street, London, EC3V 0HR United Kingdom.

The Company's ordinary shares are listed on AIM, a market regulated by the London Stock Exchange plc.

The principal activity of the Company is that of investment holding in the production and exploration of oil and gas.

2. BASIS OF PREPARATION

The Company meets the definition of a qualifying entity under FRS 100, and as such these financial statements have been prepared in accordance with Financial Reporting Standard 101 *Reduced Disclosure Framework* (FRS 101). The financial statements have been prepared under the historical cost convention.

As permitted by s408 of the Companies Act 2006 the Company has elected not to present its own statement of profit or loss and other comprehensive income for the period. The profit attributable to the Company is disclosed in the footnote to the Company's statement of financial position. The auditor's remuneration for the audit is disclosed in Note 11 of the consolidated financial statements. The Company has also applied the following disclosure exemptions under FRS 101:

- paragraphs 45(b) and 46 to 52 of IFRS 2 *Share-based Payment* (details of the number and weighted average exercise prices of share options, and how the fair value of goods or services received was determined), as equivalent disclosures are included within the consolidated financial statements;

- all requirements of IFRS 7 *Financial Instruments: Disclosures*, as equivalent disclosures are included in the consolidated financial statements;

- paragraphs 91 to 99 of IFRS 13 *Fair Value Measurement* (disclosure of valuation techniques and inputs used for fair value measurement of assets and liabilities);

- paragraph 38 of IAS 1 *Presentation of Financial Statements* - the requirement to disclose comparative information in respect of:
  - paragraph 79(a)(iv) of IAS 1 (a reconciliation of the number of shares outstanding at the beginning and end of the period); and
  - paragraph 73(e) of IAS 16 *Property, Plant and Equipment* (reconciliations between the carrying amount at the beginning and end of the period).

- IAS 7 *Statement of Cash Flows*;

- paragraphs 30 and 31 of IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors* (the requirement for the disclosure of information when an entity has not applied a new IFRS that has been issued but is not yet effective); and

- paragraph 17 of IAS 24 *Related Party Disclosures* (key management compensation), and the other requirements of that standard to disclose related party transactions entered into between two or more members of a group, provided that any subsidiary which is a party to the transaction is wholly owned by such a member.

3. ACCOUNTING POLICIES

The Company's accounting policies are aligned with the Group's accounting policies as set out within the consolidated financial statements, with the addition of the following:

Investment in subsidiaries

Investments in subsidiaries are held at cost less any accumulated allowance for impairment losses. Investment in subsidiaries also consist of capital contribution by the Company to its subsidiaries by assuming the ownership of the LTIP awards previously granted by the former parent company of the Group.

4. CRITICAL ACCOUNTING JUDGEMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

In the process of applying the Company's accounting policies, the Directors are required to make judgements, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised, if the revision affects only that period, or in the period of the revision and future periods, if the revision affects both current and future periods.

The following is the critical judgement and estimate that the Directors have made in the process of applying the Company's accounting policies that have the most significant effect on the amounts recognised in the financial statements.

- **Recoverability of the loan to a subsidiary, Jadestone Energy Holdings Ltd**

  The recoverability of the loan is based on the evaluation of expected credit loss. A considerable amount of estimation uncertainty exists in assessing the ultimate realisation of the loan, including the past collection history from Jadestone Energy Holdings Ltd ("JEHL") plus estimation of the future profitability of JEHL, with its sole source of income being dividend income to be received from JEHL's subsidiaries. Accordingly, the Directors exercised judgement in estimating the future profitability of the oil and gas operations held by the JEHL's subsidiaries.

  In estimating the future profitability of the JEHL's subsidiaries, Directors estimated the available reserves owned by the subsidiaries and performed sensitivity analysis on the estimated reserves as disclosed in Note 3 of the consolidated financial statements. Directors concluded that the subsidiaries will be able to declare sufficient dividend income to JEHL based on the estimated reserves and also after taking into the account the sensitivity analysis as disclosed in Note 3 of the consolidated financial statements.

  Directors also considered the future hydrocarbon prices in determining the future profitability of the JEHL's subsidiaries. The future hydrocarbon price assumptions used are highly judgemental and may be subject to increased uncertainty given climate change and the global energy transition. Directors further take into consideration the impact of climate change on estimated future commodity prices with the application of the Paris aligned price assumptions as disclosed in Note 3 of the consolidated financial statements. Based on the analysis performed, the potential future reduction on the hydrocarbon prices as impacted by the climate change and the global energy transition will not significantly impact the future operating cash flows of the subsidiaries. Accordingly, Directors estimate that the subsidiaries will be able to declare sufficient dividend income to JEHL.

5. INVESTMENT IN SUBSIDIARIES

	2023 **USD'000**	**2022** **USD'000**
Unquoted share, at cost	-*	-*

Share-based payment:		
At beginning of year	26,838	25,905
Share-based compensation at subsidiaries during the year	760	933
At end of year	**27,598**	**26,838**
	27,598	**26,838**

* Rounded to the nearest thousand.

Details of the direct and indirect investments the Company holds are as follows:

Name of the company	Place of incorporation	% voting rights and ordinary shares held 2023	% voting rights and ordinary shares held 2022	Nature of business
Direct				
Jadestone Energy Holdings Ltd (1)	England and Wales	100	100	Investment holdings
Indirect				
Jadestone Energy (Australia) Pty Ltd (2)	Australia	100	100	Production of oil & gas
Jadestone Energy (Australia Holdings) Pty Ltd (2)	Australia	100	100	Investment holdings
Jadestone Energy (CWLH) Pty Ltd (2)	Australia	100	100	Production of oil & gas
Jadestone Energy (Eagle) Pty Ltd (2)	Australia	100	100	Production of oil & gas
Jadestone Energy Inc. (3)	Canada	100	100	Investment holdings
Jadestone Energy International Holdings Inc. (3) (a)	Canada	-	100	Investment holdings
Jadestone Energy (Lemang) Pte Ltd (4)	Singapore	100	100	Exploration
Jadestone Energy Ltd (5)	Bermuda	100	100	Investment holdings
Jadestone Energy (Malaysia) Pte Ltd (4) (b)	Singapore	100	-	Production of oil & gas
Jadestone Energy (New Zealand) Ltd (6) (c)	New Zealand	-	100	Production of oil & gas
Jadestone Energy (New Zealand Holdings) Ltd (6) (d)	New Zealand	-	100	Investment holdings
Jadestone Energy (Ogan Komering) Ltd (7) (e)	Canada	-	100	Production of oil & gas
Jadestone Energy (PHT GP) Limited (1) (f)	England and Wales	100	-	Investment holdings
Jadestone Energy (PM) Inc. (9)	Bahamas	100	100	Production of oil & gas
Jadestone Energy Pte Ltd (4) (g)	Singapore	100	-	Investment holdings
Jadestone Energy (Singapore) Pte Ltd (4)	Singapore	100	100	Investment holdings
Jadestone Energy Sdn Bhd (10)	Malaysia	100	100	Administration
Jadestone Energy (Thailand) Pte Ltd (4) (h)	Singapore	100	-	Investment holdings
Jadestone Energy UK Services Ltd (1)	England and Wales	100	100	Administration
Jadestone Energy (Vietnam) Pte Ltd (4) (i)	Singapore	-	100	Exploration
Mitra Energy (Philippines SC- 56) Ltd (5)	Bermuda	100	100	Exploration
Mitra Energy (Philippines SC- 57) Ltd (8) (j)	BVI	-	100	Exploration
Mitra Energy (Vietnam 05-1) Pte Ltd (4) (k)	Singapore	-	100	Exploration
Mitra Energy (Vietnam Nam Du) Pte Ltd (4)	Singapore	100	100	Exploration
Mitra Energy (Vietnam Tho Chu) Pte Ltd (4)	Singapore	100	100	Exploration
PHT Partners LP (11) (l)	Delaware	100	-	Investment holdings

Registered office addresses:
(1) 6th Floor, 60 Gracechurch Street, London, EC3V 0HR United Kingdom
(2) Atrium Building Level 2, 168-170 St Georges Terrace, Perth WA 6000, Australia

(2) Atrium Building Level 2, 168-170 St Georges Terrace, Perth WA 6000, Australia
(3) 10th Floor, 595 Howe St., Vancouver BC, V6C 2T5, Canada
(4) 3 Anson Road #13-01, Springleaf Tower, Singapore 079909
(5) 3rd Floor - Par la Ville Place, 14 Par la Ville Road, Hamilton HM08, Bermuda
(6) Bell Gully, 171 Featherston Street, Wellington Central, Wellington, 6011, New Zealand
(7) 29 Tuscany Hills Bay NW, Calgary, Alberta, T3L2G5, Canada
(8) TMF (BVI) Ltd, Palm Grove House, P.O. Box 438, Road Town, Tortola, British Virgin Islands
(9) H&J Corporate Services Ltd, Ocean Centre, Montagu Foreshore, East bay Street, P.O. Box N-3247, Nassau, Bahamas
(10) Level 15-2, Bangunan Imperial Court, Jalan Sultan Ismail, 50250, Kuala Lumpur, Malaysia
(11) CT Corporation, 1209 Orange St, Wilmington, DE 19801, United States

(a) Jadestone Energy International Holdings Inc. was amalgamated with Jadestone Energy Inc. on 16 May 2023 as part of the Company's internal reorganisation.

(b) Jadestone Energy (Malaysia) Pte Ltd was incorporated on 19 January 2023 for production of oil and gas operations.

(c) Jadestone Energy (New Zealand) Ltd was dissolved on 30 August 2023.

(d) Jadestone Energy (New Zealand Holdings) Ltd was dissolved on 27 October 2023.

(e) Jadestone Energy (Ogan Komering) Ltd was dissolved on 10 March 2023.

(f) Jadestone Energy (PHT GP) Limited was acquired by the Group from the acquisition of interest in Sinphuhorm gas field.

(g) Jadestone Energy Pte Ltd was incorporated on 16 January 2023 for investment holdings purposes.

(h) Jadestone Energy (Thailand) Pte Ltd was incorporated on 19 January 2023 for investment holdings purposes.

(i) Jadestone Energy (Vietnam) Pte Ltd was dissolved on 6 November 2023.

(j) Mitra Energy (Philippines SC- 57) Ltd was dissolved on 30 October 2023.

(k) Mitra Energy (Vietnam 05-1) Pte Ltd was dissolved on 9 March 2023.

(l) PHT Partners LP was acquired by the Group from the acquisition of interest in Sinphuhorm gas field.

6. STAFF NUMBER AND COSTS

The Company had one employee at the beginning of the year. The employee was transferred to a subsidiary during the year. The Company had one employee in 2022.

The aggregate remuneration comprised:

	2023 USD'000	2022 USD'000
Wages and salaries	9	141
Social security costs	-	38
Defined contribution pension costs	-	-
	9	**179**

7. RELATED PARTY TRANSACTIONS

The Company did not enter into new loan with its subsidiary during the year

Amount owing by subsidiaries are mainly related to payments on behalf, and a receipt on behalf of the Company by a subsidiary for the proceeds from issuance of shares during the period. The amount owing by subsidiaries are non-trade in nature, unsecured, non-interest bearing and repayable on demand.

Amount owing to a subsidiary is mainly related to advances received for the purpose of depositing the funds into the Company's bank account. The amount owing to subsidiaries are non-trade in nature, unsecured, non-interest bearing and repayable on demand.

During the year, the Company entered into the following transactions with:

	2023 USD'000	2022 USD'000
Loan to a subsidiary		
At beginning of the year	252,485	365,598
Repayment during the year	(52,865)	(68,284)
Unrealised foreign exchange differences	17,492	(44,829)
At end of the year	**217,112**	**252,485**

Subsidiaries

Advances	41,608	31,971
Repayment received	(33,583)	(4,200)
Payment on behalf by	65,328	(61)
Repayment made	7,525	-

Placement of additional shares and issue of warrants

On 6 June 2023, the Company completed an equity fundraising, creating an additional 94,081,826 ordinary shares at GB£0.45 per share, which comprised of a placing and subscription of 92,312,691 new ordinary shares to existing and new institutional shareholders and a placing and subscription of 1,769,135 new ordinary shares to the Directors of the Company. Tyrus has subscribed to 24,883,387 of new ordinary shares under the equity fundraising for a consideration of US$13.9 million.

The placing and subscription of 1,769,135 new ordinary shares to the Directors of the Company as follows:

	Number of shares	**Consideration paid USD'000**
A. Paul Blakeley	336,311	188
Bert-Jaap Dijkstra	71,556	40
Dennis McShane	178,889	100
Iain McLaren	22,222	12
Robert Lambert	111,269	62
Cedric Fontenit	333,333	186
Lisa Stewart	178,889	100
David Neuhauser	447,222	250
Jenifer Thien	89,444	50
	1,769,135	**988**

In support of the equity fundraising, the Company has entered into an up to US$50.0 million equity underwrite debt facility agreement with Tyrus. The equity underwrite facility reduced to zero following the total funds raised from the equity fundraising and the open offer exceeded US$50.0 million. The Company incurred upfront fee of US$2.15 million and interest of US$27,778 from the equity underwrite facility, which was recorded as finance costs in Note 14 of the consolidated financial statements.

As part of the underwritten placing of additional ordinary shares, the Company has also entered into a warrant instrument with Tyrus for 30 million ordinary shares at an exercise price of 50 pence per share. The warrants are exercisable within 36 months from the date of issuance, with an expiry date of 5 June 2026.

Committed standby working capital facility

On 6 June 2023, the Company entered into a committed standby working capital facility with Tyrus for a facility size of up to US$35.0 million. The standby working capital facility was finalised at US$31.9 million, after deduction of US$3.1 million of excess funds from the total gross funds of US$53.1 million raised from the equity placing and open offer. The facility will mature on 31 December 2024. The facility bears interest of 15% on drawn amounts and 5% on undrawn amounts and can be repaid or cancelled without penalties. The standby working capital facility was not utilised during 2023 and remained undrawn as at 31 December 2023. For the year ended 31 December 2023, the Company had incurred interest expense of US$3.6 million, which was recorded as finance costs in Note 14 of the consolidated financial statements.

8. SHARE CAPITAL AND SHARE PREMIUM ACCOUNT

	No. of shares	**Share capital USD'000**	**Share premium account USD'000**
Issued and fully paid			
As at 1 January 2022, at £0.001 each	465,081,238	358	201
Issued during the year	1,446,108	2	782
Share repurchases	(18,173,683)	(21)	-
As at 31 December 2022	**448,363,663**	**339**	**983**
Issued during the year	94,463,933	120	50,844
Share repurchased	(2,051,022)	(3)	-
As at 31 December 2023	**540,766,574**	**456**	**51,827**

On 2 August 2022, the Company announced the launch of a share buyback programme (the "Programme") in accordance with the authority granted by the shareholders at the Company's annual general meeting on 30 June 2022. The maximum amount of the Programme was US$25.0 million, and the Programme was not to exceed 46,574,528 ordinary shares.

On 19 January 2023, the Companysuspended its share buyback programme. For the year ended 31 December 2023, the Company had acquired 2.3 million shares at a weighted average cost of GB£0.75 per share, resulting in total expenditure of US$2.1 million. The total nominal value of the shares repurchased was US$2,485. All shares repurchased were cancelled. Since the launch of the share buyback programme, a total of 20.4 million shares had been acquired for a total accumulated expenditure of US$18.1 million, total nominal value of the shares repurchased was US$23,778.

As at 31 December 2022, the Company did not have a liability in respect to the remaining unutilised amount of US$8.9 million under the Programme as the Company had full discretion over the number of shares to be repurchased. The Programme expired on 30 June 2023 in conjunction with the Company's 2023 annual general meeting ("AGM") and was not renewed at the 2023 AGM.

On 6 June 2023, the Company completed an equity fundraising, creating an additional 94,081,826 ordinary shares at GB£0.45 per share, which comprised of a placing and subscription of 92,312,691 new ordinary shares to existing and new institutional shareholders and a placing and subscription of 1,769,135 new ordinary shares to the Directors of the Company. Total gross proceeds were US$53.0 million, with net proceeds of US$51.0 million. The Group incurred total costs of US$2.0 million associated with the equity fundraising and these costs were accounted as a deduction to the equity.

On 9 June 2023, the Company launched an open offer of up to 14,887,039 new ordinary shares, at GB£0.45 per share, to raise additional proceeds of up to EUR8.0 million[1] (up to US$8.6 million). The open offer closed on 28 June 2023, raising a total of US$42,009 by issuing 73,557 new shares.

During the year, employee share options of 128,160 were exercised and issued at an average price of GB£ 0.56 per share (2022: 1,446,108; GB£0.42 per share). Additionally, 79,327 shares were issued during the year to satisfy the Company's obligations with regards to the performance shares and 101,063 shares were issued to meet the obligations with regards to the restricted shares.

The Company has one class of ordinary share. Fully paid ordinary shares with par value of GB£0.001 per share carry one vote per share without restriction, and carry a right to dividends as and when declared by the Company.

[1] The open offer was quoted in Euro of 8.0 million to meet the applicable regulation issued by the European Union regarding to the quantum of open offer.

9. DIVIDENDS

The Company has sufficient distributable reserves to declare dividends. The distributable reserves were created through the reduction of share capital of the Company in May 2021. The dividends declared were in compliance with the Act.

The Company did not declare any dividend during the year.

On 20 September 2022, the Directors declared a 2022 interim dividend of 0.65 US cents/share, equivalent to a total distribution of US$3.0 million. The dividend was paid on 11 October 2022.

On 6 June 2022, the Directors recommended a final 2021 dividend of 1.34 US cents/share, equivalent to a total distribution of US$6.2 million, or US$9.0 million in respect of total 2021 dividends. The dividend was approved by shareholders on 30 June 2022 and paid on 5 July 2022.

10. SHARE-BASED PAYMENTS RESERVE

The total expense arising from share-based payments of US$0.8 million (2022: US$0.1 million) was recognised in profit or loss for the year ended 31 December 2023. The share-based payment expense arise from share options, performance shares and restricted shares awarded from 2020 to 2022. In view of the performance of the Group in 2023, the Remuneration Committee suspended performance share grants in 2023. In consultation with an external advisor, the Remuneration Committee approved a Deferred Cash Plan ("DCP") for the 2023 - 2026 Long-Term Incentive ("LTI") cycle, which was awarded in October 2023 (Note 40 to the consolidated financial statements). This was done to ensure that the LTI programme aligns the interests of the senior leaders of the Group to the interests of shareholders, and is effective in retaining and incentivising our top talents.

On 15 May 2019, the Company adopted, as approved by the shareholders, the amended and restated stock option plan, the performance share plan, and the restricted share plan (together, the "LTI Plans"), which establishes a rolling number of shares issuable under the LTI Plans up to a maximum of 10% of the Company's issued and outstanding ordinary shares at any given time. Options under the stock option plan will be exercisable over periods of up to 10 years as determined by the Board.

10.1 Share options

The Directors have applied the Black-Scholes option-pricing model, with the following assumptions, to estimate the fair value of the options at the date of grant:

	Options granted on 9 March 2022
Risk-free rate	1.34% to 1.38%
Expected life	5.5 to 6.5 years
Expected volatility[1]	63.0% to 66.7%
Share price	GB£ 1.01
Exercise price	GB£ 0.92
Expected dividends	1.96%

[1] Expected volatility was determined by calculating the average historical volatility of the daily share price returns over a period commensurate with the expected life of the awards for a group of ten peer companies.

10.2 Performance shares

The performance measures for performance shares incorporate both a relative and absolute total shareholder return ("TSR") calculation on a 70:30 basis to compare performance vs. peers (relative TSR) and to ensure alignment with shareholders (absolute TSR).

Relative TSR: measured against the TSR of peer companies; the size of the payout is based on Jadestone's ranking against the TSR outcomes of peer companies.

Absolute TSR: share price target plus dividend to be set at the start of the performance period and assessed annually; the threshold share price plus dividend has to be equal to or greater than a 10% increase in absolute terms to earn any pay out at all, and must be 25% or greater for target pay out.

A Monte Carlo simulation model was used by an external specialist, with the following assumptions to estimate the fair value of the performance shares at the date of grant:

	Performance shares granted on 9 March 2022
Risk-free rate	1.39%
Expected volatility[2]	53.1%
Share price	GB£ 1.01
Exercise price	N/A
Expected dividends	1.71%
Post-vesting withdrawal date	N/A
Early exercise assumption	N/A

[2] Expected volatility was determined by calculating Jadestone's average historical volatility of each trading day's log growth of TSR over a period between the grant date and the end of the performance period.

10.3 Restricted shares

Restricted shares are granted to certain senior management personnel as an alternative to cash under exceptional circumstances and to provide greater alignment with shareholder objectives. These are shares that vest three years after grant, assuming the employee has not left the Group. They are not eligible for dividends prior to vesting.

The following assumptions were used to estimate the fair value of the restricted shares at the date of grant, discounting back from the date they will vest and excluding the value of dividends during the intervening period:

	Restricted shares granted on	
	22 August 2022	**9 March 2022**
Risk-free rate	1.73%	1.39%
Share price	GB£ 0.90	GB£ 1.01
Expected dividends	1.73%	1.71%

The following table summarises the options/shares under the LTI plans outstanding and exercisable as at 31 December 2023:

			Shares Options			
	Performance shares	**Restricted shares**	**Number of options**	**Weighted average exercise price GB£**	**Weighted average remaining contract life**	**Number of options exercisable**
As at 1 January 2022	1,486,893	151,633	21,166,802	0.45	7.15	11,409,854
New options/share awards issued	1,406,956	293,655	1,030,366	0.92	9.19	-
Vested during the year	-	-	-	0.50	6.27	2,010,007
Accelerated vesting during the year	-	-	-	0.46	6.45	1,354,702
Exercised during the year	-	-	(1,446,108)	0.42	-	(1,446,108)
Cancelled during the year	(147,906)	-	(1,012,124)	0.50	-	(1,012,124)
As at 31 December 2022	**2,745,943**	**445,288**	**19,738,936**	**0.45**	**7.15**	**12,316,331**
Vested during the year	(79,327)	(101,063)	-	0.44	6.32	4,665,000
Exercised during the year	-	-	(128,160)	0.56	-	(128,160)
Expired unexercised during the year	(449,513)	-	-	-	-	-
Cancelled during the year	-	-	(344,655)	0.60	-	(344,655)
As at 31 December 2023	**2,217,103**	**344,225**	**19,266,121**	**0.48**	**5.37**	**16,508,516**

The weighted average share price on the exercise date is GB£0.83 (2022: GB£0.86).

	Number of options	Range of exercise price GB£	Weighted average exercise price GB£	Weighted average remaining contract life
Share options exercisable as at 31 December 2022	12,316,331	0.26 - 0.99	0.41	5.46
Share options exercisable as at 31 December 2023	16,508,516	0.26 - 0.99	0.41	4.92

11. OTHER PAYABLES

	2023 USD'000	2022 USD'000
Other payables	563	456
Accruals	892	395
	1,455	**851**

Other payables and accruals principally comprise amounts outstanding for on-going business expenditures. The average credit period is less than 30 days. For most suppliers, no interest is charged on the payables in the first 30 days from the date of invoice. Thereafter, interest may be charged on outstanding balances at varying rates of interest. The Company has financial risk management policies in place to ensure that all payables are settled within the pre-agreed credit terms.

12. WARRANTS LIABILITY

On 6 June 2023, in consideration of the support provided to the Company under the equity underwrite debt facility and committed standby working capital facility, the Company entered into a warrant instrument with Tyrus Capital S.A.M. and funds managed by it, for 30 million ordinary shares at an exercise price of 50 pence sterling per share. The warrants are exercisable within 36 months from the date of issuance, with an expiry date of 5 June 2026.

The Directors have applied the Black-Scholes option-pricing model, with the following assumptions, to estimate the fair value of the warrants as at 31 December 2023:

Risk-free rate	3.77%
Expected life	2.5 years
Expected volatility[1]	54.5%
Share price	GB£ 0.37
Exercise price	GB£ 0.50
Expected dividends	0%

[1] Expected volatility was determined by calculating the average historical volatility of the daily share price returns over a period commensurate with the expected life of the awards for a group of ten peer companies.

13. EVENTS AFTER THE END OF THE REPORTING PERIOD

Acquisition of additional interest in the CWLH oil fields

On 14 November 2023, the Group has executed a sale and purchase agreement with Japan Australia LNG (MIMI) Pty Ltd (the "Seller"), to acquire the Seller's non-operated 16.67% working interest in the Cossack, Wanaea, Lambert, and Hermes ("CWLH") oil fields development, offshore Western Australia, for a total initial cash consideration of US$9.0 million, and certain subsequent Abandonment Trust Payments (the "Acquisition").

The Acquisition was completed on 14 February 2024, with a net receipt to the Group from the Seller of US$6.3 million, reflecting the accumulated economic benefits of the CWLH assets for the period from the effective date of 1 July 2022 to completion. As a result, the Group's non-operated working interest in the CWLH assets increased to 33.33%, from 16.67%.

Redetermination of the Borrowing Base under the Reserves-Based Lending Facility

On 26 April 2024, the RBL Banks finalised a routine redetermination of the borrowing base under the RBL, with the revised borrowing capacity of US$200.0 million. Stag has been removed from the borrowing base assets and replaced with the second acquisition of 16.67% of the CWLH assets, acquired on 14 February 2024. The next scheduled redetermination is scheduled to complete by 30 September 2024.

Suspension and restoration of trading on AIM

On 13 February 2024, the ordinary shares of the Company were suspended from trading pursuant to a proposed sale by Woodside Energy Group Ltd. ("Woodside") of its participating interests in the Macedon and Greater Pyrenees Projects offshore Western Australia (the "Proposed Acquisition"). Had Jadestone been selected as the preferred bidder and reached agreement with Woodside on acquisition terms, the Proposed Acquisition would have been classified as a reverse takeover transaction in accordance with AIM Rule 14, and accordingly, the Company's ordinary shares were suspended from trading on AIM on 13 February 2024. On 11 April 2024, Woodside cancelled the sale of its participating interests in those assets. With the possibility of the Proposed Acquisition ceasing, the Company's shares resumed trading on AIM on 11 April 2024.

Change in Board of Directors

On 25 January 2024, the Company announced the appointment of Joanne Williams as an independent non-executive director. Ms. Williams is Chair of both the HSEC Committee and the Montara Technical Committee, and a member of the Audit Committee.

On 25 March 2024, the Company announced the appointment of Adel Chaouch as an independent non-executive director. On the same day, the Company announced the resignation of (i) Lisa Stewart as an independent non-executive director and (ii) Robert Lambert as an independent non-executive director.

On 27 March 2024, the Company announced the resignation of Dennis McShane as an independent non-executive director and Chair of the Board. On the same day, the Company announced the election of Adel Chaouch as Chair of the Board. Dr. Chaouch is Chair of the Governance and Nomination Committee, and a member of both the Remuneration Committee and the HSEC Committee.

END

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