RNS Number : 3062J
Jadestone Energy PLC
20 May 2025

2024 Full Year Results

Delivering to expectations, increasing resilience, guidance maintained

20 May 2025-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 audited financial statements (the "Financial Statements"), as at and for the financial year ended 31 December 2024.

The Company will host a webcast at 1:00 p.m. UK time today, details of which can be found in the announcement below.

2024 operational performance demonstrates benefit of diversified portfolio

- Over 10 million manhours worked without a lost-time injury (LTI) across the Group's Indonesia and Malaysia operations.
- Delivered record annual production of 18,696 boe/d in 2024 (+35% year-on-year).
- Successful completion and start-up of the Akatara field, further diversifying the Group's production base, with gas sales commencing in July 2024 and the contractual performance test completing in December 2024.
- 10% reduction in adjusted unit operating costs in 2024 to US 33.68/boe (2023: US 37.24/boe)
- Independently audited 1P reserves by ERCE of 48.6 mmboe at year-end 2024, with a 1P reserves replacement ratio of more than 200%, greatly increasing the Group's resilience.
- Independently audited 2P reserves by ERCE of 68.3 mmboe at year-end 2024, resulting in a 2P reserves replacement ratio of 104% and a 10-year 2P reserve life, based on 2024 production
- Year-end 2024 2C resources increased by 19% year-on-year to 125.7 mmboe, or 18 years resource life based on 2024 production. Approximately 75% of the 2C resource base relates to the significant resource contained in the Group's gas discoveries offshore Vietnam.

Stable and resilient financial position

- 2024 revenues increased by 28% year-on-year to US 395.0 million (2023: US 309.2 million)
- Adjusted EBITDAX for 2024 of US 127.9 million, a 41% increase year-on-year, driven primarily the increase in revenues.
- Operating cash flow pre working capital for 2024 of US 70.5 million, a 93% increase on 2023 (US 36.5 million)
- Net debt of US 104.8 million at 31 December 2024 (31 December 2023: US 3.6 million net debt) has reduced to US 54.2 million at 30 April 2025, reflecting c.US 112.5 million of consolidated Group cash balances and US 167.0 million of debt drawn under the Group's reserve-based lending facility (RBL Facility).
- Signed a US 30 million working capital facility with a 31 December 2026 maturity. The working capital facility will be used for general corporate purposes, providing additional liquidity to the Group, if required.
- Available liquidity of US 142.5 million at 30 April 2025, including the undrawn working capital facility referenced above.
- Approximately 1.7 mmbbls of hedges in place covering the nine months ending 30 September 2025 at a weighted average hedge price of US 69.07/bbl.
- Certain of Jadestone's shareholders have requested that the Company seek authority to repurchase shares at the 2025 AGM on 20 June 2025.

Current trading and outlook - a strong start to 2025

- Strong portfolio performance year-to-date 2025, with production for the first four months of 2025 averaging 20,830 boe/d, a 22% increase year-on-year and an annual record for this period.
    - Akatara has delivered robust performance year-to-date in 2025, with gross production averaging approximately 6,200 boe/d and 96% facilities uptime, both ahead of plan.
- **<u>All guidance metrics unchanged:</u>**
    - 2025 average production of 18-21,000 boe/d (post Sinphuhorm sale).
    - 2025 operating costs of US 250-300 million.
    - 2025 capital expenditure of US 75-95 million.
    - 2025-2027 free cash flow (pre debt servicing) guidance[1] of US 270-360 million.
- Active portfolio management with the sale of the Group's non-operated Thailand assets in April 2025 for an upfront consideration of US 39.4 million and contingent payments of US 3.5 million.

- Submission of the field development plan for the commercialization of the Nam Du/U Minh (NDUM) discoveries offshore southwest Vietnam to Petrovietnam, commencing the regulatory approval process.
- Skua-11ST well operations ongoing, to accelerate recovery of reserves from the Skua structure and extending the economic life of the Montara field by one year. Results expected in June 2025.
- Debottlenecking project at Akatara progressing, accelerating the commercialization of up 3.5 mmboe of reserves.
- In line with previous announcements, Jadestone has been reviewing its organizational and cost structure, with the aim of ensuring that the Group is run as efficiently as possible and enhancing its resilience to oil price cycles, while maintaining the highest safety standards. As part of this review, the Group will reduce the headcount of its Australian onshore office in Perth by approximately 25%. The targeted headcount reductions do not impact the Group's offshore Australia workforce. Jadestone's Australian asset portfolio remains a core focus for the Group and its growth ambitions.
- The Group continues to explore strategic acquisition opportunities to drive value and deliver scalable growth.

Dr. Adel Chaouch, Executive Chairman, commented:

"We closed 2024 on a very positive note, with the notable achievements of safely bringing Akatara onstream and doubling our interest in CWLH both contributing to our record production for the year, reducing unit opex and enhancing the resilience of the

Group.

Jadestone's refreshed and reinvigorated management team is delivering on its promises. We have seen a strong performance from our diverse portfolio so far in 2025, delivering record production for the first four months of the year and importantly, in line with guidance. Our focus on operational excellence and maintaining high uptime levels across the portfolio is paying off, providing confidence for our shareholders in our full year guidance and targets, which are reiterated today. In particular, we are very pleased at the initial performance of the Akatara field, where uptime and production early in 2025 has been ahead of plan, and we are confident that the cash flows and value from this asset will be the foundation of Jadestone's success for years to come.

Our operational progress is being delivered against a backdrop of enhanced macroeconomic uncertainty. Greater asset diversification due to successful growth, the onset of fixed price gas production from Akatara, our near-term oil price hedges and the premium to Brent for our oil sales means we are well-placed to weather oil price volatility. We are also taking action to make Jadestone a more resilient business to oil price cycles, by targeting reductions in both operating costs and overheads. We have strengthened the balance sheet with net debt reduced by approximately half in the first four months of 2025 and we have put in place a new working capital facility, resulting in liquidity at the end of April of US 142.5 million - a strong position from which to continue executing our 2025 activity program.

Jadestone has a rare and compelling investment proposition. We have the skillset that covers both mid-life oil assets and greenfield gas developments, and a significant presence and platform to operate in three of the top five upstream producing countries in the Asia-Pacific region. We continue to actively look for opportunities to achieve the scale which is increasingly important in the oil and gas sector, but we will only allocate capital in a way that will be accretive to shareholders."

Dr. Adel Chaouch

EXECUTIVE CHAIRMAN

2024 SUMMARY

US '000 except where indicated	2024	2023
Total hours worked lost-time injury free (million)	4.93	4.55
Total recordable injury rate	2.51	0.86
Proven plus Probable Reserves (mmboe) - 31 December	68.3	68.0
Sales volume, total liquids and gas, barrels of oil equivalent (boes)	5,284,718	3,862,742
Production, boe/day[1]	18,696	13,813
Realized oil price per barrel of oil equivalent (US /boe)[2]	85.21	87.34
Realized gas price per thousand standard cubic feet (US /mcf)	3.91	1.53
Revenue[3]	395,036	309,200
Production costs	(276,969)	(232,772)
Impairment of oil and gas properties	-	(29,681)
Adjusted unit operating costs per barrel of oil equivalent (US /boe)[4]	33.68	37.24
Adjusted EBITDAX[4]	127,895	90,647
(Loss)/Profit after tax	(44,141)	(91,274)
(Loss)/Earnings per ordinary share: basic & diluted (US)	(0.08)	(0.18)
Operating cash flows before movement in working capital	70,526	36,499
Capital expenditure	74,459	115,882
Net (debt)/cash[4] at 31 December	(104,774)	(3,596)

Operational and financial summary

- Proven and Probable (2P) reserves at 31 December 2024 increased slightly year-on-year to 68.3 mmboe (2023: 68.0 mmboe), driven by 6.7 mmboe of new reserves associated with the acquisition of a further 16.67% stake in the CWLH fields and minor upward revisions at Akatara and Sinphuhorm offsetting production in the year of 6.8 mmboe. Total 2P reserve additions of 7.1 mmboe during 2024 resulted in a 104% 2P reserve replacement ratio for the year.
- Production rose 35% year-on-year to a record 18,696 boe/d (2023: 13,813 boe/d), primarily due to the CWLH 2 acquisition (+1,816 bbls/d), a full year of Montara production (+1,607 bbls/d) and commencement of production at Akatara (+977 boe/d).
- Total sales volume of oil, gas, LPG and condensate in 2024 increased by 36% to 5.3 mmboe (2023: 3.9 mmboe), reflecting the increase in production.
- Total revenue increased by 28% to US 395.0 million (2023: US 309.2 million) due to higher sales volumes, slightly offset by a lower realized oil price. Total 2024 revenue includes a hedging loss of US 27.4 million (2023: US 10.3 million) from commodity swap contracts associated with the RBL Facility.
- The average realized oil price for the year before hedging was US 85.21/bbl in 2024 (2022: US 87.34/bbl). The average realized price premium for 2024 was US 3.76/bbl (2023: US 5.58/bbl).The lower premium year-on-year reflects a shift in the weighting of sales, with a greater proportion of CWLH crude and lower proportion of Stag crude in 2024 compared to 2023.
- Reported production costs totalled US 277.0 million in 2024, a 19% increase from US 232.8 million in 2022. The majority (US 30.7 million) of the increase is explained by the (non-cash) change in lifting and inventory movements year-on-year.
    - 2024 adjusted unit operating costs[3] of US 33.68/boe represented a 10% decrease over the prior year (2023: US 37.24/boe) primarily due to lower operating cost production at CWLH and Akatara added to the production mix during the year.
- Impairment of oil and gas properties was nil in 2024, compared to US 29.7 million in 2023 due to impairments at Stag and non-producing assets offshore Malaysia.
- Adjusted EBITDAX for 2024 increased by 41.2% to US 127.9 million, up from US 90.6 million in 2023, driven by the factors set out above.
- 2024 loss after tax of US 44.1 million (2023: US 91.3 million loss after tax), driven by the factors set out above

- 2024 operating cash flow before movements in working capital of US 70.5 million, a increase of 93% compared to 2023 (US 36.5 million).
- 2024 capital expenditure of US 74.5 million reduced 36% year-on-year (2023: US 115.9 million), primarily due to the completion of the Akatara development project.
- Net debt of US 105.0 million at 2024 year-end (2023 year-end: US 3.6 million), reflected a full drawdown of US 200.0 million from the RBL Facility and total cash and cash equivalents of US 95.0 million.
  - The scheduled RBL March 2025 redetermination concluded on 2 April 2025, resulting in a borrowing base of US 167.0 million for the six month period ending 30 September 2025, which is currently fully drawn.

[1] 2024 Production includes Sinphuhorm gas and condensate 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 recognizes dividends received. Accordingly, the revenue and production costs associated with Sinphuhorm are excluded from the Group's financial results.

[2] Realized oil price represents the actual selling price inclusive of premiums or discounts to Brent.

[3] Revenue in 2024 of US 395.0 million (2023: US 309.2million) includes a hedging loss of US 27.4 million (2023: US 10.3 million) from the commodity swap contracts associated with 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 in the Non-IFRS Measures section of this document.

Enquiries

Jadestone Energy plc. Phil Corbett, Head of Investor Relations	+44 7713 687 467 (UK) ir@jadestone-energy.com
Stifel Nicolaus Europe Limited (Nomad, Joint Broker) Callum Stewart / Jason Grossman / Ashton Clanfield	+44 (0) 20 7710 7600 (UK)
Peel Hunt LLP (Joint Broker) Richard Crichton / David McKeown / Georgia Langoulant	+44 (0) 20 7418 8900 (UK)
Camarco (Public Relations Advisor) Billy Clegg / Georgia Edmonds / Poppy Hawkins	+44 (0) 203 757 4980 (UK) jadestone@camarco.co.uk

Full-year 2024 presentation webcast
The Company will host an investor and analyst presentation at 1:00 p.m. (UK time) on Tuesday, 20 May 2025, including a question-and-answer session, accessible through the link below:

Webcast link: https://www.investis-live.com/jadestone-energy/681de341f8132e000ea6c65a/nehyi
Event title: Jadestone Energy Full-Year 2024 Results
Time: 1:00 p.m. (UK time)
Date: 20 May 2025

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://www.netroadshow.com/events/global-numbers?confId=70236
Access Code: 722579

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, while 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 minimized.

2024 saw a significant increase in work hours, reaching 5.41 million (2023: 4.64 million), largely driven by intensified commissioning efforts at the Akatara Gas Processing Facility (AGPF) in Indonesia. Lagging metrics were met with zero life altering events, zero major environmental events and one LTI, at a rate of 0.18 / million manhours, exceeding industry safety benchmarks (the 2024 target was less than the 2023 IOGP average of 0.242). A lost-time injury occurred at Montara when a worker injured his shoulder.

The Group experienced four high potential incidents in 2024, a reduction of 33% from 2023. Two were related to dropped objects and there were two electrical near misses. Dropped objects were a focus in 2024, resulting in a 60% reduction year-on-year. Jadestone continues to learn from near misses and share learnings, both internally and externally.

At the AGPF, construction was largely completed at the beginning of the year, with the focus in first year half on equipment testing, pre-commissioning, and commissioning, along with a successful workover campaign on five existing wells supplying gas to the facility. On 18 June 2024, mechanical completion was achieved at the plant, marking the start of final commissioning and production ramp-up. First export gas was achieved on 31 July 2024 and the 72-hour performance test was completed on 9 December 2024. Completion of the performance test marked the conclusion of the commissioning phase at Akatara, with responsibility for day-to-day operations transitioning from the EPCI contractor to Jadestone. During this busy period, Jadestone's team maintained safe operations, logging over four million hours worked without an LTI.

One Tier 1 process safety event was recorded at the AGPF, where a gas detector was activated due to a crack in the small bore piping on an export compressor. The compressor was shut down, isolated and depressurized and an investigation revealed that additional bracing was required to bring vibration within acceptable levels. After additional bracing was installed, post start-up checks confirmed vibration was within acceptable levels.

Net Zero interim targets

Jadestone's strategy for maximizing reserves from existing producing oil and gas fields explicitly precludes frontier exploration and new greenfield development, a position that is informed by 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, committed to upholding climate targets and achieving its Net Zero interim reduction targets.

The Group is committed to reduce Scope 1 and 2 GHG emissions (in tonnes of CO_2-e) from its operated assets by 20% by 2026 and by 45% by 2030, relative to 2021 levels. This commitment applies to emissions from the Group's existing operated assets. Jadestone will make best endeavours to retain GHG reduction levels when integrating future acquisitions into the interim targets, subject to reviews of GHG abatement opportunities.

The Group's gross Scope 1 GHG emissions during 2024 amounted to 587 kilo tonnes CO_2-e (2023: 480 kilo tonnes CO_2-e[2]). The year-on-year increase reflects several factors, including significantly higher uptime at Montara during 2024 and the addition of the Akatara field to Jadestone's producing portfolio. Jadestone does not consume any purchased electricity at any of its operated sites. Its indirect, Scope 2, GHG emissions from the consumption of purchased electricity at its offices and warehouses accounts for less than 1% of Scope 1 and 2 GHG emissions combined.

Jadestone intends that its interim GHG emissions reduction targets will be achieved through a combination of measures, ranging from operational GHG reductions, including minimizing flaring, as well as reliance on carbon credits within the regulatory schemes of Jadestone regions. For further details, refer to Jadestone's 2024 Annual Report as well as the Sustainability Report, which will be published by the end of May 2025.

Governance

The Board gained a variety of skillsets and experience throughout 2024 and into early 2025 with the longer-term objective to ensure that the Board is sized appropriate to the Company's scale and ambition, while maintaining appropriate capabilities and adhering to corporate governance standards.

Joanne Williams was appointed on 25 January 2024 as an independent Non-Executive Director. Dr. Adel Chaouch was appointed to the Board on 25 March 2024 as an independent Non-Executive Director and elected as Chair of the Board on 27 March 2024 after Dennis McShane stepped down. Additionally, both Lisa Stewart and Robert Lambert stepped down from the Board effective 25 March 2024.

Linda Beal was appointed as an independent Non-Executive Director and Audit Committee Chair on 9 May 2024. Iain McLaren did not seek re-election at the Company's AGM and stepped down from the Board on 13 June 2024.

Andrew Fairclough was appointed as Executive Director and Chief Financial Officer (CFO) on 29 October 2024 replacing the Group's former CFO, Bert-Jaap Dijkstra, who stepped down as CFO and Executive Director on the same date.

During the second half of 2024, the Board evaluated the performance of the Group and its management team, comparing actual outcomes against targets and the resulting share price performance. After consulting material shareholders of the Company, the Board subsequently decided that a change in Jadestone's management team was required to best position the Group for future success. As a result, Paul Blakeley stepped down as Executive Director, President, and CEO effective 5 December 2024. The Board decided that Dr. Chaouch, with his extensive upstream experience and management roles, would be best placed to provide leadership, through combining the CEO role with his existing duties as Chairman of the Board. Dr. Chaouch's appointment as Executive Chairman is on a fixed-term basis, with appropriate incentives to ensure alignment with shareholders and drive the success of the Group. At the same time and in alignment with the QCA Code guidance and good governance practice, Linda Beal was appointed as Senior Independent Director.

Given the management changes highlighted above, and while a search for a Chief Executive Officer was progressed, the Board concluded that Joanne Williams had the experience and skills to support the management team through this period. She agreed to take an operational role as Chief Operating Officer on a fixed term basis. After taking external advice, the Non-Executive Directors determined that Joanne Williams would remain an independent Non-Executive Director while performing her management role during this period.

On 16 January 2025, David Mendelson was appointed as an independent Non-Executive Director and Cedric Fontenit stepped down as an independent Non-Executive Director effective 20 January 2025.

The Board is progressing the appointment of an appropriate candidate as CEO.

OPERATIONAL REVIEW

Producing Assets

Australia

<u>Montara Project (100% working interest, operated)</u>

The Montara fields averaged 5,262 bbls/d in 2024, compared to 3,655 bbls/d in 2023. The year-on-year increase is primarily explained by higher uptime and availability of the Montara Venture FPSO in 2024, after Montara production was shut-in during early 2023 for repairs and maintenance activity on the FPSO's storage tanks. Montara production in the second half of 2024 also benefitted from the return to production of the H6 and Swift-2 wells, which had been offline due to mechanical issues.

Following the significant activity on the FPSO's oil storage tanks since 2022, the Montara Venture's storage capacity has now increased to over 600,000 barrels[3]. Increasing oil storage availability allowed for the temporary shuttle tanker offloading arrangement to be phased out during the fourth quarter of 2024, reducing transportation costs. The Group offloading arrangement to be phased out during the fourth quarter of 2024, reducing transportation costs. The Group expects to resume the FOB sale of larger cargoes of Montara crude from mid-2025 onwards, further reducing lifting-related costs.

The Group's main capital activity during 2025 is the drilling of the Skua-11 sidetrack well (Skua-11ST), which commenced in April. This well has dual objectives of decommissioning the original Skua-11 well and drilling a sidetrack into the Skua structure up-dip of the original Skua-11 well path. Based on pre-drill expectations, a successful Skua-11ST well would accelerate recovery of reserves from the Skua structure and extend the economic life of the Montara Project by one year.

In total, seven cargoes totaling 1.9 mmbbls (2023: five cargoes of 1.2 mmbbls) were lifted from Montara in 2024, with an average realization of US 83.68/bbl (consisting of an average Brent price of US 80.20/bbl and average premium of US 3.48/bbl). This compares to an average realization of US 84.79/bbl in 2023 (Brent US 80.97/bbl and premium US 3.82/bbl).

<u>CWLH (33.33% working interest, non-operated)</u>

On 14 February 2024, the Group completed the acquisition of an additional 16.67% working interest in the Cossack, Wanaea, Lambert and Hermes oil fields offshore western Australia, doubling its working interest to 33.33%.

During 2024, Jadestone's net production from the CWLH fields averaged 3,711 bbls/d, compared to 1,896 bbls/d in 2023. The year-on-year change is primarily explained by the increase in the Group's working interest referenced above. However, the CWLH asset outperformed expectations in 2024 with average production 6% ahead of the Group's forecast, driven by better than expected reservoir performance.

Following engagement with the CWLH joint venture, total abandonment trust fund payments associated with the acquisition of the additional 16.67% interest were finalized at US 83.8 million, all of which was paid in 2024.

The Group lifted two cargoes of 1.3 mmbbls (2023: one cargo of 0.7 mmbbls) from CWLH in 2024 for an average realization of US 82.38/bbl (consisting of an average Brent price of US 83.20/bbl and an average discount of US 0.82/bbl). This compares to a realization of US 82.81/bbl in 2023 (Brent US 83.18/bbl and discount of US 0.37/bbl) for the one cargo lifted in 2023.

<u>Stag (100% working interest, operator)</u>

Stag field production averaged 2,006 bbls/d in 2024, compared to 2,671 bbls/d in 2023.

Production in 2023 benefited from the initial production impact of the Stag-50H and 51H wells drilled in November 2022. Stag field production in 2024 reflected the impact of weather-related downtime in the early part of the year, and mechanical issues in several wells which required workovers to restore output. Attempts to restore production from the Stag-48H well during 2024 and early 2025 were unsuccessful, with further activity on this well under review.

Several initiatives are currently underway to address the well reliability and uptime issues at Stag that have impacted production in recent years, with Stag production increasing during the first half of 2025 as a result. The Stag field's operating cost structure is also being reviewed to ensure that asset cash flows and the economic life of the field can be maximized.

Work continues on the Stag-52H and 53H infill drilling targets to improve payback duration and returns prior to a sanction decision on either well.

The Group sold three Stag cargoes totaling 0.7mmbbls in 2024 (2023: four cargoes totaling 1.0 mmbbls). Premiums for Stag crude have remained strong, with the average realization for 2024 sales of US 95.93/bbl (Brent US 82.18/bbl and premium US 13.75/bbl), compared to an average 2023 realization of US 94.16/bbl (Brent US 81.13/bbl and premium US 13.03/bbl).

Indonesia

<u>Akatara (100% working interest[4], operator)</u>

The Akatara field is located within the Lemang PSC onshore Sumatra in Indonesia. Akatara was previously developed as an oil field, prior to being redeveloped by Jadestone to commercialize gas, condensate and LPG reserves located in shallower zones.

Development activity at Akatara finished in the first half of 2024, culminating in a declaration of mechanical completion at the Akatara Gas Processing Facility in June 2024, and the introduction of reservoir gas from one of the five production wells, with condensate production also commencing at this point.

Commissioning of the facility continued during the second half of 2024, with facility uptime and production volumes steadily increasing as several commissioning issues were encountered and addressed.

The Akatara gas development successfully completed its formal EPCI contract performance test in December 2024. This required a continuous 72-hour test of the AGPF at full production rates, representing the daily contract quantity under the Akatara gas sales agreement and associated LPG and condensate production. This milestone marked the conclusion of the commissioning phase at Akatara, with responsibility for day-to-day operations at the AGPF transitioning from the EPCI contractor to Jadestone.

Akatara production, on an annual average basis, was 977 boe/d in 2024 (2023: nil). A total of 1.2 bcf of gas was sold in 2024 at an average price of US 5.97/mcf, with initial Akatara LPG and condensate sales totaling approximately 150,000 barrels, which were sold for a weighted average price of US 56.69/bbl.

Akatara performance in early 2025 has been ahead of expectations, with 96% AGPF uptime year-to-date and gross production averaging approximately 6,200 boe/d. The focus in 2025 is to implement a series of minor plant upgrades during the scheduled annual shut down in May 2025, which will enhance the overall resiliency of the AGPF.

The Group continues to progress its plans to increase the capacity of the AGPF through a debottlenecking project. It is now expected that the debottlenecking project will follow a phased approach, with an increase in AGPF capacity in mid-2025 through modifying and optimizing plant gas processing, with the remainder of the proposed increase in capacity coming in the second half of 2026 following engineering, procurement and installation of additional processing equipment. The phased approach will result in an earlier increase in plant capacity than previously expected, with lower upfront costs and is still expected to accelerate the production of 3.5 mmboe of reserves.

The HSE performance at Akatara has been highly impressive, with over eight million manhours having been worked to date in both the development and production phase without a lost-time injury.

Malaysia

PM323 PSC (60% working interest, operator)

The PM323 PSC produced an average of 3,484 bbls/d net to Jadestone's working interest in 2024 (2023: 2,203 bbls/d). The year-on-year increase was due to the positive impact of the Group's infill drilling program on the East Belumut field in late 2023.

The Group is progressing plans for further infill drilling on the East Belumut field in 2026, focusing on the undrained southwestern area of the field discovered during the 2023 drilling campaign.

A total of 0.6 mmbbls (2023: 0.4 mmbbls) were lifted from the PM323 PSC during 2024, with an average realization of US 84.30/bbl (2023: US 86.99/bbl).

PM329 PSC (70% working interest, operator)

The PM329 PSC produced an average of 1,501 boe/d net to Jadestone's working interest in 2024, consisting of 1,024 bbls/d of oil and 2.9 mmcf/d of gas (2023: 2,085 boe/d, consisting of 1,461 bbls/d of oil and 3.7 mmcf/d of gas). The year-on-year decrease is due to natural decline.

A total of 0.3 mmbbls of oil (2023: 0.3 mmbls) were lifted from the PM329 PSC in 2024, with an average realization of US 83.89/bbl (2023: US 86.82/bbl). In addition, approximately 1.0 bcf of gas was sold at an average realization of US 1.60/mcf.

Puteri Cluster (100% working interest, operator)

In July 2024, Jadestone was awarded a 100% participating interest in the Puteri Cluster Production Sharing Contract (the Puteri Cluster PSC, previously referred to as the SFA Cluster PSC) offshore Peninsular Malaysia. The Puteri Cluster PSC covers an area of 348km^2 in shallow water offshore Peninsular Malaysia located adjacent to the Group's existing operated PM323 and PM329 PSCs and is surrounded by the PM428 PSC (see below).

The Puteri Cluster PSC contains the Penara, Puteri-Padang and North Lukut fields, assets in which Jadestone previously held a 50% non-operated interest (through the PM318 and AAKBNLP PSCs) following the Group's entry into Malaysia in August 2021.

Jadestone currently estimates that the Puteri Cluster PSC contains approximately 15.4 mmbbls of gross 2C contingent resources. The Group is continuing its technical assessment of the Puteri Cluster PSC ahead of a decision to submit a field development and abandonment plan to PETRONAS.

PM428 PSC (60% working interest, operator)

In January 2024, Jadestone was awarded a 60% operated interest in the PM428 PSC offshore Peninsular Malaysia. The PM428 PSC is adjacent to the PM323 and PM329 PSCs and surrounds the Puteri Cluster PSC (referenced above). The PM428 PSC carries a minimal financial commitment to reprocess existing seismic and contains several prospects which, in a success case, could be developed through existing infrastructure currently operated by Jadestone

Thailand

Sinphuhorm (9.52% working interest, non-operated)

During 2024, the Sinphuhorm field produced an average of 1,755 boe/d (1,734 boe/d gas and 21bbls/d of condensate). Production for 2023 averaged 1,303 boe/d (expressed as an annual average from completion of the Sinphuhorm acquisition on 23 February 2023). The year-on-year increase in 2024 reflected the partial ownership in 2023, strong gas demand in northern Thailand in the second half of 2024, the successful commissioning of a booster compression project in 2024 and robust performance from recent infill wells.

Due to a lack of influence over the day-to-day operational activities at Sinphuhorm, the Group did not recognize its share of revenues and production costs, instead recognizing dividend income when received from APICO LLC. Dividends of US 8.2 million were received in 2024 (2023: US 4.3 million).

On 16 April 2025, the Group announced that it had sold its Thailand interests to a subsidiary of PTTEP, the Thailand national oil and gas company, for a cash consideration of US 39.4 million, with a further US 3.5 million in contingent payments depending on future license extensions.

Pre-production Assets

Vietnam

Block 51 PSC (100% working interest, operator) and Block 46/07 PSC (100% working interest, operator)

In January 2024, the Group announced that it had signed a Heads of Agreement (HoA) with Petrovietnam Gas Joint Stock Corporation for the Gas Sales and Purchase Agreement (GSPA) relating to the Nam Du and U Minh (NDUM) gas fields development, located in the Block 46/07 and Block 51 Production Sharing Contracts in shallow waters offshore southwest Vietnam

Vietnam.

Following signature of the HoA, the Group commenced detailed negotiations over a fully termed GSPA, which are currently well advanced. The HoA also allowed for the submission in March 2025 of an updated field development plan (FDP) for the NDUM fields, the approval of which is required before a final investment decision can be taken. The FDP specifies the development concept for the NDUM fields, associated capital and operating cost estimates, and a schedule to first gas.

The Block 46/07 PSC includes a commitment to drill an additional exploration well. In February 2024, Jadestone submitted an application to extend the commitment period and proposed that the well be incorporated into the Nam Du field development drilling program. As at 31 December 2024, the Field Development Plan (FDP) incorporating the commitment well, had not yet been submitted for approval. The company has recognised a provision of US 10.0 million in respect of this obligation. Subsequent to the year-end, the Company submitted the FDP on 18 March 2025.

The Group continues to work with Petrovietnam and other government entities to obtain a suspension of the relinquishment obligation for Block 51, which contains the Tho Chu discovery.

Reserves and resources

Total 2P Reserves[1] (net, mmboe)

	Australia	Malaysia[2]	Indonesia[2]	Thailand[3]	Total Group
Opening balance, 1 January 2024	**31.6**	**9.2**	**23.3**	**3.9**	**68.0**
Acquisitions	6.7	-	-	-	**6.7**
Technical revisions	(0.2)	-	0.1	0.5	**0.4**
Production	(4.0)	(1.8)	(0.4)	(0.6)	**(6.8)**
Ending balance, 31 December 2024	**34.1**	**7.4**	**23.0**	**3.8**	**68.3**

As at 31 December 2024, the Group had 2P Reserves of 68.3 mmboe, a slight increase compared with 31 December 2023, after accounting for production in 2024. New 2P reserves of 6.7 mmboe were booked on the closing of an additional 16.67% interest in CWLH fields in February 2024. There were minor upward technical revisions at the Akatara field in Indonesia and Sinphuhorm in Thailand, with the latter due to higher forecast gas demand through to the end of license expiry in 2031. Collectively, these 7.1 mmboe of positive revisions were sufficient to offset production of 6.8 mmboe, representing 104% 2P reserve replacement during the year.

ERC Equipoise Limited independently evaluated the Group's year-end 2024 reserves.

Total 2C Contingent Resources[4] (net, mmboe)

	Australia	Malaysia	Indonesia[2]	Thailand[3]	Vietnam[2]	Total Group
Opening balance, 1 January 2024	**5.1**	**1.2**	**0.9**	**4.4**	**93.9**	**105.6**
Acquisitions	5.5	-	-	-	-	5.5
Transfer to 2P reserves	-	-	-	-	-	-
Technical revisions	-	15.1	-	(0.4)	-	14.7
Ending balance, 31 December 2024	**10.6**	**16.3**	**0.9**	**4.0**	**93.9**	**125.7**

Group 2C resources as at 31 December 2024 are estimated at 125.7 mmboe, an increase of 19% year-on-year, mainly reflecting the addition of 2C resources associated with the Puteri Cluster PSC award during the year and the CWLH 2 acquisition in February 2024. Approximately 75%, or 93.9 mmboe, of the Group 2C resources at 31 December 2024 relates to the significant resource contained in the Group's gas discoveries offshore Vietnam.

[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] Assumes oil equivalent conversion factor of 5,740 scf/boe. The Group disposed of its assets in Thailand on 16 April 2025 to a subsidiary of Thailand's national oil and gas company, PTTEP, for an initial consideration of US 39.4 million and contingent payments of US 3.5 million.

[4] Contingent Resources based on Jadestone estimates as at 31 December 2024, 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 2024.

US '000 except where indicated	2024	2023
Production, boe/ day[1]	18,696	13,813
Oil and liquids sales, barrels of oil equivalent (boes) [2]	4,764,875	3,634,991
Realized oil price per barrel of oil equivalent (US /bbl)[3]	85.21	87.34
Gas sales, thousand standard cubic feet (mcf)	2,216,652	1,366,505
Realized gas price per thousand standard cubic feet (US /mcf)	3.91	1.53
Sales volume for LPG and condensates, barrels (bbls)	150,401	-
Realized LPG and condensate price per barrel (US /bbl)[3]	56.69	-
Revenue[4]	395,036	309,200
Production costs	(276,969)	(232,772)
Adjusted unit operating costs per barrel of oil equivalent (US /boe)[5]	33.68	37.24
Adjusted EBITDAX[5]	127,895	90,647

Unit depletion, depreciation and amortization (US /boe)	12.45	14.14
Impairment of assets	-	(29,681)
(Loss) before tax	(43,435)	(102,766)
(Loss) after tax	(44,141)	(91,274)
(Loss) per ordinary share: basic and diluted (US)	(0.08)	(0.18)
Operating cash flows before movement in working capital	70,526	36,499
Capital expenditure	74,459	115,882
Net (debt)/cash at 31 December	(104,964)	(3,596)

Benchmark commodity price and realized price

The actual average realized price in 2024 decreased by 2% to US 85.21/bbl, from US 87.34/bbl in 2023. The benchmark Dated Brent price remained virtually flat at US 81.45/bbl in 2024, compared to US 81.76/bbl in 2023. The reduction in the realized price was predominately due to the decline in the average premium to US 3.76/bbl in 2024, compared to US 5.58/bbl in 2023. The lower premium reflected a change in the composition of sale volumes, with CWLH crude comprising a higher proportion of sale volumes in 2024, compared to higher premium Stag barrels in 2023. The Stag premium in 2024 averaged US 13.75/bbl (2023: 13.03/bbl), compared to the CWLH average discount at US 0.82/bbl (2023: average discount at US 0.37/bbl).

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

[2] Sales volumes include oil, condensate and LPG.

[3] Realized oil price represents the actual selling price inclusive of premiums or discounts.

[4] Revenue in 2024 and 2023 includes a hedging charge of US 27.4 million and U 10.3 million respectively from the commodity swap contracts associated with the RBL Facility.

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

Production and liftings

Production for 2024 was 18,696 boe/d, an increase of 4,883 boe/d compared to 13,813 boe/d in 2023. This overall increase was driven by the following key factors:

- The acquisition of a further 16.67% interest in CWLH increased production to 3,711 bbls/d in 2024 compared to 1,896 bbls/d in 2023;
- Montara achieved a full year production in 2024 of 5,262 bbls/d, compared to 2023 of 3,655 bbls/d, after production resumed in March 2023 following repairs to the Montara Venture FPSO's tanks;
- Akatara completed commissioning and start-up activities with first commercial production achieved on 31 July 2024 at annual average rate of 977 boe/d;
- Production from the PenMal Assets increased by 697 boe/d in 2024 to 4,985 boe/d (2023: 4,288 boe/d) due to the successful infill drilling campaign at the end of 2023 on the PM323 PSC; and
- Sinphuhorm production increased year-on-year in 2024 to 1,755 boe/d (2023: 1,303 boe/d) reflecting a full-year of asset ownership, commissioning of a booster compressor at the field and strong gas demand in northern Thailand.

The increase was partly offset by:

- Production at Stag decreased by 665 bbls/d in 2024 to 2,006 bbls/d (2023: 2,671 bbls/d) due to extended downtime caused by adverse weather conditions and downhole mechanical issues in wells which required workovers.

Throughout the year, the Group completed 21 crude liftings compared to 19 in 2023, leading to oil sales totalling 4.8 mmbbls, up from 3.6 mmbbls in 2023. Condensate and liquefied petroleum gas (LPG) produced from Akatara lifted a combined 0.15 mmbbls starting the second half of 2024 upon commencement of of Akatara field (2023: nil)

The Group recorded a sale of 1,047.1 mmcf and 1,169.6 mmcf of gas from the PenMal Assets and Akatara respectively in 2024, compared to 1,366.5 mmcf of gas in 2023 from the PenMal Assets.

Revenue

The Group generated net revenue after hedging effects of US 395.0 million in 2024, an increase of 28% compared to 2023 of US 309.2 million. The increase of US 85.8 million was predominately due to:

- An increase in lifted volumes by 1.1 mmbbls year-on-year resulting in increased revenue of US 96.3 million; and
- Akatara generated US 14.9 million after first gas on 31 July 2024, consisting of US 6.4 million from gas sales, US 4.3million of LPG and US 4.2 million of condensate sales.

The increase was partly offset by:

- Hedging losses increased US 17.1 million to US 27.4 million in 2024, based on a weighted average hedging price of US 69.07/bbl from the commodity swap contracts associated with the RBL Facility compared to loss of US 10.3 million in 2023 (the hedging contracts commenced in October 2023);
- Lower average realized price in 2024 of US 85.21/bbl (2023: US 87.34/bbl), resulting in a revenue decrease of US 7.7 million; and
- Revenue generated in 2024 from PM329 gas sales decreased US 0.5 million to US 1.6 million in 2024 compared to US 2.1 million in 2023.

Production costs

Production costs increased by 19% in 2024 to US 277.0 million, from US 232.8 million in 2023, amounting to an increase of US 44.2 million.

	2024 US '000	2023 US '000	Variance US '000
Operating costs	111,736	98,723	13,013
Workovers	20,797	17,562	3,235
Logistics	26,928	34,109	(7,181)
Repairs and maintenance	70,304	55,572	14,732
Tariffs and transportation costs	8,451	7,502	949
Supplementary payments and royalties	17,342	16,056	1,286
Decommissioning expenses	-	12,545	(12,545)
Underlift, (overlift) and crude inventories movement	21,411	(9,297)	30,708
	276,969	**232,772**	**44,197**

The year-on-year increase was predominately due to the following factors:

- Operating costs increased by US 13.0 million to US 111.7 million in 2024, compared to US 98.7 million in 2023, due to several factors. The increase includes US 15.4 million for CWLH due to the additional interest acquired in February 2024. Operating costs at the PenMal Assets were higher by US 4.2 million due to inventory adjustments. Akatara incurred US 4.8 million of operating costs following first gas in July 2024. These increases were offset by reductions at Montara and Stag which decreased by US 11.4 million, due to reduced costs for crude tanker hire rates, lower diesel consumption by US 4.4 million and the non-recurring waste disposal cost for NORMs (naturally occurring radioactive material) was US 1.0 million lower in 2024.

- Workover costs increased by US 3.2 million to US 20.8 million in 2024, compared to US 17.6 million in 2023. This rise was primarily driven by complex well-integrity repairs at Stag, which cost US 2.2 million more than the previous year. Additionally, the PenMal Assets incurred US 2.9 million in workover costs during 2024 for well integrity and performance improvements.

- Logistical costs decreased by US 7.2 million to US 26.9 million in 2024 from US 34.1 million, primarily due to a US 4.9 million reduction at Montara following the unavailability of helicopters, which led to lower standing charges, and a US 3.0 million decrease at PenMal's Puteri Cluster due to minimal offshore activity after the demobilization of the FPSO. These reductions were partially offset by a US 0.6 million increase at Stag, where multiple cyclone events in 2024 required more frequent use of support vessels and helicopters compared to 2023.

- Repairs and maintenance (R&M) increased by US 14.7 million, rising to US 70.3 million in 2024 from US 55.6 million in 2023. Akatara recorded US 6.0 million R&M following the start of commercial production. Montara's costs rose by US 3.3 million due to an ROV campaign and subsea inspections, while the PenMal Assets incurred an additional US 3.0 million from engine overhauls on producing assets and topsides flushing and pipeline preservation works at the Puteri Cluster facilities. Stag saw a net increase of US 2.4 million for one-off remedial works on the CALM buoy and export pipeline.

- Supplementary payments and royalties increased by US 1.3 million in 2024 due to higher production-based royalties at Montara, CWLH and Akatara. This was offset with a decrease at PenMal Assets.

- The PenMal Assets incurred a one-off decommissioning expense of US 12.5 million in 2023, related to decommissioning activities on the Bunga Kertas FPSO at the PNLP Assets.

- Underlift, overlift and crude inventories movement (non-cash) increased US 30.7 million driven by the second acquisition of 16.67% of the CWLH assets in February 2024. The acquired underlift was valued at US 40.5 million and was included in inventory movements until it was sold as part of the March 2024 lifting. Apart from the CWLH underlift, the net year-on-year movement generated a credit of US 9.8 million reflecting a decrease in inventory movements across the asset portfolio.

The adjusted unit operating cost per barrel of oil equivalent in 2024 was US 33.68/boe (2023: US 37.24/boe)(please refer to the Non-IFRS measures section later in this document). The decrease was primarily due to the change in the production mix, principally the lower operating costs at Akatara and CWLH.

Depletion, depreciation and amortization (DD&A)

DD&A charges increased to US 91.4 million in 2024, up from US 76.1 million in the prior year. The rise was primarily driven by higher production at Montara, which accounted for an additional US 16.8 million, and the commencement of production at Akatara, contributing US 2.6 million. These uplifts were partially offset by a US 5.6 million reduction at Stag due to lower output, and a US 1.6 million decrease at CWLH, attributed to the application of IFRS 3 (Business Combinations) purchase price accounting following the increase in the Group's interest in February 2024.

In 2024, the Group's right-of-use asset depreciation increased by US 0.9 million to US 16.2 million compared to US 15.3 million in 2023. This increase was primarily attributable to the full-year depreciation effect of leases that were either signed or renewed during 2023.

There was a decrease in the overall depletion cost on a unit basis, reducing to US 12.45/boe in 2024 from US 14.14/boe in 2023. This reduction was mainly due to the reclassification of Akatara's capitalized development costs to production assets for depletion, which resulted in a relatively low unit depletion cost of US 3.66/boe for Akatara in 2024.

Staff costs

Total staff costs in 2024 were US 65.0 million (2023: US 56.2 million), comprising US 30.6 million (2023: US 26.0 million) in relation to offshore employees (recorded under production costs), and US 34.4 million (2023: US 30.2 million) for office-based employees. The average number of employees during the year was 422 (2023: 409), with the additional staff costs and headcount year-on-year mainly due to Akatara commencing production and onshore support in Australia. During the year, there was compensation for loss of office amounting to US 2.3 million, plus, US 0.2 million of payroll tax for the departure of the former CEO, Mr A. Paul Blakeley. These amounts were accrued in 2024 and paid in 2025.

Other expenses and allowance for expected credit losses

	2024 US '000	2023 US '000	Variance US '000
Non-recurring corporate costs	1,397	3,602	(2,205)
Recurring corporate costs and other expenses	17,009	11,742	5,267
Allowance for expected credit losses	457	-	457
Allowance for slow moving inventories	1,670	655	1,015
Assets written off	1,775	5,114	(3,339)
Net foreign exchange loss	2,008	1,728	280
	24,316	**22,841**	**1,475**

Other expenses increased US 1.5 million in 2024 to US 24.3 million (2023: US 22.8 million), predominately due to:

- Non-recurring corporate costs fell by US 2.2 million to US 1.4 million in 2024. This reduction included US 0.9 million of business development fees, and US 0.5 million of financing fees. The 2023 total was US 3.6 million, with US 2.2 million for business development, US 0.8 million for reorganization costs, US 0.4 million for an equity fundraising and US 0.2 million for financing fees.

- Recurring corporate costs increased by US 5.3 million to US 17.0 million in 2024 (2023: US 11.7 million). While general administrative expenses for office operations, professional services and travel remained consistent year-over-year, the increase was due to a full-year of dividend based royalties at Sinphuhorm, withholding taxes and higher professional fees related to executive recruitment, consulting fees and other expenses.

- The allowance for expected credit losses in 2024 of US 0.5 million (2023: Nil) represents a specific bad debt provision created against a customer during the year.

- The allowance for slow-moving materials and spares more than doubled to US 1.6 million in 2024 from US 0.7 million in 2023, due to an increase in slow-moving inventory related to supplies.

- Assets written off decreased by US 3.3 million in 2024, with total write-offs of US 1.8 million compared to US 5.1 million in 2023. The 2024 write-offs mainly related to US 1.8 million for obsolete Montara materials and spares. In contrast, the 2023 write-offs were higher, including US 3.1 million from the cancellation of the Skua-12 well project and US 2.1 million for obsolete inventory.

- Net foreign exchange loss of US 2.0 million in 2024 (2023: US 1.7 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 2024.

Finance costs

Finance costs in 2024 were US 45.1 million (2023: US 41.8 million), an increase of US 3.3 million predominately due to:

- Interest fees for the RBL Facility increased by US 8.3 million to US 16.4 million (2023: US 8.1 million). The increase reflects higher borrowings and full year of interest and expenses compared to a partial period of expense incurred in 2023 (the RBL Facility was signed in May 2023).

- Accretion fees for the Asset Retirement Obligation (ARO) increased by US 2.4 million to US 22.6 million (2023: US 20.2 million), predominantly due to the additional ARO recognized for CWLH working interest acquired in 2024;

The above increased was offset by:

- The warrant reserve generated a decrease of US 3.5 million in 2024, as the reserve was created during the 2023 equity raise, resulting in a US 3.5 million charge in that year. In 2024, there was no movement on the reserve. The revaluation of the warrant liability is included in Other Financial Gains.

- Upfront fees and interest associated with the working capital facility and financing facilities decreased by US 1.3 million to US 2.4 million, compared to US 3.7 million in 2023.

- The accretion expense for Akatara long-term VAT receivables decreased by US 1.0 million to US 0.2 million in 2024 compared to US 1.2 million in 2023.

- Changes in fair value of contingent payments in 2024 of US 0.1 million, a US 0.8 million decrease compared to US 0.9 million in 2023.

- RBL commitment fees in 2024 of US 0.1 million, a US 0.3 million decrease compared to US 0.4 million in 2023.

Other income

The Group generated US 29.6 million of other income in 2024, an increase of US 10.7 million (2023:US 18.9 million) predominately due to:

- The change in ARO provisions generated a gain ofUS 13.8 million in 2024 (2023: US Nil) primarily related to CWLH (US 11.0 million) and the PenMal Assets (US 2.8 million), driven by changes in underlying assumptions.

- Interest income increased US 3.0 million, due to the CWLH decommissioning trust fund interest increasing US 3.4 million to US 6.3 million (2023: US 2.9 million) following the additional contributions made during the year and an additional US 0.3 million to US 1.3 million (2023: US 1.0 million) earned from the placement of fixed deposits.

The above increases were offset by:

- Other provisions decreased by US 6.5 million to a gain of US 1.1 million (2023: US 7.6 million) due to a change in underlying assumptions for provisions for contingent payments and manpower related provisions.

- The Montara helicopter rebate decreasedUS 0.7 million to US 5.7 million in 2024, compared to US 6.4 million in 2023. The lower rebate in 2024 was due to services being provided for only one helicopter unit, compared to two units in 2023.

Other financial gains

Other financial gains increased US 2.6 million in 2024, due to the revaluation of the warrant liability. The warrant liability is revalued at each reporting date. This gain reflects a reduction in the liability from US 3.5 million in 2023 to US 0.9 million in 2024.

Share of result of associates

During 2024, the Group recognized its share of profits from the Sinphuhorm field amounting to US 1.5 million (2023: US 2.6 million). The Group disposed of its Thailand assets in April 2025.

Impairment

No impairment was recorded in 2024. In 2023, the Group impaired the Stag oil and gas properties by US 17.4 million and US 12.3 million impairment on the PNLP Assets oil and gas properties due to revised ARO estimates.

Taxation

The tax expense of US 0.7 million in 2024 (2023: US 11.5 million of tax credit) includes a current tax charge of US 7.1 million (2023: US 10.8 million) and a deferred tax credit of US 6.4 million (2023: deferred tax credit of US 22.3 million).

During the year, tax payments comprised US 14.7 million (2023: US 5.3 million) for Australian corporate taxes. Additionally, there were US 12.3 million (2023: US 7.5 million) in Malaysian petroleum income tax (PITA) payments.

The weighted average effective tax rate for operating jurisdictions in Australia and Malaysia was 35% in 2024, based on the profit-making entities within each jurisdiction, compared to 54% in 2023. There was an increase in the deferred tax asset during 2024, resulting from the income tax credits that are generated as trading losses which are carried forward for offset against future taxable profits.

US '000	**2024 US '000**	**2023 US '000**
Loss before tax	(43,435)	(102,766)
Expected effective tax rate	35%	54%
Tax at the country level effective rate	**(15,335)**	**(55,494)**
Effect of different tax rates in loss making jurisdictions	5,011	13,975
Malaysia PITA tax losses on non-operated PSCs	8,275	10,060
Utilization of PRRT credits	(10,031)	17,795
PRRT tax refund	(1,700)	1,735
Non-deductible expenses	839	399
Income not subject to tax	(1,897)	-
Deferred tax permanent differences	5,473	2,155
PRRT permanent differences	(1,149)	(4,269)
Deferred tax asset not recognised	12,049	-
Adjustment in respect to prior years	(829)	2,152
Tax expense/(credit) for the year	**706**	**(11,492)**

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 26% in 2024 (2023: 42%) being lower due to the utilization of PRRT credits brought forward and current year business tax losses. Montara and CWLH have approximately US 4.1 billion (2023: US 3.8 billion) and US 802.4 million (2023: US 493.4 million) of unutilized 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 2024, resulting from income tax credits as trading losses are carried forward for offsetting 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.

Indonesia taxes

The Indonesia corporate income tax rate is applied at 30% of Indonesia corporate taxable income. Corporate and Dividend Tax ("C&D") is calculated at 20% of sales revenue less certain permitted deductions and is tax deductible for Indonesia corporate income tax purposes. There is no tax expense during the year for Indonesia tax due to the Lemang asset as it is not in a taxable income position.

RECONCILIATION OF CASH

US '000	2024			2023
Cash and cash equivalents at the beginning of year		**153,404**		**123,329**
Revenue	395,036		309,200	
Other operating income	6,889		6,574	
Production costs	(276,969)		(232,772)	
Staff costs	(34,016)		(29,431)	
General and administrative expenses	(20,414)		(17,072)	
Operating cash flows before movements in working capital		**70,526**		**36,499**
Movement in working capital		10,491		6,837
Placement of decommissioning trust fund for CWLH Assets		(83,773)		(41,000)
Net tax paid		(27,907)		(14,461)
Investing activities				
Purchases of intangible exploration assets, oil and gas properties, and plant and equipment[1]		(50,510)		(109,524)
Cash paid on acquisition of Sinphuhorm Assets		-		(27,853)
Dividends received from associate		8,660		3,842
Cash received on acquisition of CWLH		5,236		-
Other investing activities		7,492		4,451
Financing activities				
Net proceeds from issuance of shares		-		50,964
Shares repurchased		-		(2,084)
Repayment of lease liabilities		(18,985)		(17,171)
Total drawdown of borrowings		43,000		232,000
Repayment of borrowings		-		(75,000)
Repayment of costs and interests of borrowings		(19,086)		(13,260)
Other financing activities		(3,322)		(4,165)
Total cash and cash equivalent at the end of year		**95,226**		**153,404**

[1] Total capital expenditure was US 74.4 million (2023: US115.9 million), comprising total capital expenditure paid of US 50.5 million (2023: US 109.5 million), accrued capital expenditure of US 18.8 million (2023: US 4.0 million) and capitalization of borrowing costs of US 5.1 million (2023: US 2.4 million).

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 debt/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, 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.

US '000 except where indicated	2024	2023
Production costs (reported)	276,969	232,772
Adjustments		
Lease payments related to operating activity[1]	17,538	16,155
Underlift, overlift and crude inventories movement[2]	(21,411)	9,297
Workover costs[3]	(20,797)	(17,562)
Other income[4]	(5,731)	(6,375)
Non-recurring operational costs[5]	(8,840)	(19,654)
Non-recurring repair and maintenance[6]	(2,850)	(1,773)
Transportation costs[7]	(8,451)	(7,502)
PenMal Assets supplementary payments and Australian royalties[8]	(17,342)	(16,056)
PenMal non-operated assets operational costs[9]	(262)	(19,273)
Adjusted production costs	**208,823**	**170,029**
Total production (barrels of oil equivalent)	6,200,334	4,566,060
Adjusted unit operating costs per barrel of oil equivalent	**33.68**	**37.24**

[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 Montara Venture FPSO.

[6] Non-recurring repair and maintenance costs in 2024 predominately related to subsea maintenance at Montara, CALM buoy coating remediation and maintenance pigging of the export flowline at Stag and rectification costs of the cranes and platforms of at one of the PenMal Assets. The cost in 2023 predominately related to the repair of a gas turbine generator at the PenMal Assets PM329 PSC.

[7] The transportation costs includes the pipeline tariff at the PenMal Assets and tanker costs at Stag and Montara associated with lifting costs.

[8] The supplementary payments are required under the terms of PSCs based on Jadestone's profit oil after entitlements between the government and joint venture partners. The Australian royalties are related to an Australian Government mandated decommissioning cost recovery levy on all upstream producers in the country, plus royalties payable from the CWLH fields to the local state government .

[9] Similar to 2023, PenMal non-operated assets operational costs in 2024 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.

Adjusted EBITDAX

Adjusted EBITDAX is a non-IFRS measure which does not have a standardized 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:

US '000	2024	2023
Revenue	395,036	309,200
Production costs	(276,969)	(232,772)
Administrative staff costs	(34,423)	(30,197)
Other expenses and allowance for expected credit losses	(24,316)	(22,841)
Share of results of associate	1,553	2,640
Other income, excluding interest income	22,122	14,404
Other financial gains	2,611	-
Unadjusted EBITDAX	**85,614**	**40,434**
Non-recurring		
Net loss from oil price and foreign exchange derivatives	27,417	10,395
Non-recurring opex[1]	11,952	40,700
Oil and gas properties written off	1,423	3,067
Change in provision - Lemang PSC contingent payments	-	(7,653)
Others[2]	1,489	3,704
	42,281	**50,213**
Adjusted EBITDAX	**127,895**	**90,647**

[1] Non-recurring opex in 2024 represents Montara interim tanker storage costs which was temporarily employed as a result of the repair work relating to the storage tanks of the FPSO. It also includes repair and maintenance costs predominately related to CALM buoy coating remediation and maintenance pigging of export flowline at Stag, subsea maintenance at Montara and rectification costs of the cranes and platform of AAKBNLP asset at PenMal. The cost in 2023 mainly consisted of one-off operational costs and major maintenance/well intervention activities, in particular operating costs and FPSO rectification costs incurred at the PNLP Assets, Montara interim tanker storage, diesel fuel consumption by the FPSO during production shutdown and to power the reinjection compressor during production start-up. It also includes repair and maintenance costs related to the repair of a gas turbine generator at PenMal Assets PM329 PSC.

[2] Includes business development costs, external funding sourcing costs and internal reorganization costs.

Net cash/debt

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

US '000	2024	2023
Borrowings (principal sum)	(200,000)	(157,000)
Cash and cash equivalents	95,226	153,404
Net (debt)/cash	**(104,774)**	**(3,596)**

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

Consolidated Statement of Profit or Loss and Other Comprehensive Income for the year ended 31 December 2024

	Notes	2024 USD'000	2023 USD'000
Consolidated statement of profit or loss			
Revenue	4	395,036	309,200
Production costs	5	(276,969)	(232,772)
Depletion, depreciation and amortisation	6	(91,407)	(76,141)
Administrative staff costs	7	(34,423)	(30,197)
Other expenses	10	(23,859)	(22,841)
Allowance for expected credit losses	10	(457)	-
Impairment of oil and gas properties	12	-	(29,681)
Share of results of associate accounted for using the equity method	23	1,553	2,640
Other income	13	29,614	18,855
Finance costs	14	(45,134)	(41,829)
Other financial gains	15	2,611	-
Loss before tax		**(43,435)**	**(102,766)**
Income tax (expense)/credit	16	(706)	11,492
Loss for the year		**(44,141)**	**(91,274)**
Loss per ordinary share			
Basic and diluted (US)	17	(0.08)	(0.18)
Consolidated statement of other comprehensive income			
Loss for the year		(44,141)	(91,274)
Other comprehensive income			
Items that may be reclassified subsequently to profit or loss:			
Loss on unrealised cash flow hedges	34	(14,849)	(30,509)
Hedging loss reclassified to profit or loss	4, 34	27,417	10,322
		12,568	**(20,187)**
Tax (expense)/credit relating to components of other comprehensive loss	16	(3,770)	6,056
Other comprehensive income		8,798	(14,131)
Total comprehensive income for the year		**(35,343)**	**(105,405)**

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

Consolidated Statement of Financial Position as at 31 December 2024

	Notes	31 December 2024 USD'000	31 December 2023 USD'000
Assets			
Non-current assets			
Intangible exploration assets	19	91,323	79,564
Oil and gas properties	20	422,239	457,202
Plant and equipment	21	10,591	10,462
Right-of-use assets	22	16,111	31,099
Investment in associate	23	19,544	26,651
Other receivables	27	274,124	141,860
Deferred tax assets	25	44,898	26,774
Cash and cash equivalents	28	888	1,008
Total non-current assets		**879,718**	**774,620**
Current assets			
Inventories	26	44,602	33,654
Trade and other receivables	27	55,044	124,379
Tax recoverable		13,863	4,085
Cash and cash equivalents	28	94,338	152,396
Total current assets		**207,847**	**314,514**
Total assets		**1,087,565**	**1,089,134**
Equity and liabilities			
Equity			
Capital and reserves			
Share capital	29	457	456
Share premium account	29	52,176	51,827
Merger reserve	31	146,270	146,270
Share-based payments reserve	32	27,730	27,673
Capital redemption reserve	33	24	24
Hedging reserve	34	(5,333)	(14,131)
Accumulated losses		(202,490)	(158,349)
Total equity		**18,834**	**53,770**

	Notes	31 December 2024 USD'000	31 December 2023 USD'000
Non-current liabilities			
Provisions	35	664,951	503,170
Borrowings	36	122,978	131,729*
Lease liabilities	37	5,308	18,746
Other payables	39	17,282	16,966
Derivative financial instruments	40	-	6,708
Deferred tax liabilities	25	59,620	65,829
Total non-current liabilities		**870,139**	**743,148**
Current liabilities			
Borrowings	36	77,212	22,844*
Lease liabilities	37	12,243	14,118
Trade and other payables	39	92,793	117,984*
Derivative financial instruments	40	7,618	13,972*
Warrants liability	41 XXX	931	3,469
Provisions	35	5,542	108,525
Tax liabilities		2,253	11,304
Total current liabilities		**198,592**	**292,216**
Total liabilities		**1,068,731**	**1,035,364**
TOTAL EQUITY AND LIABILITIES			
Total equity and liabilities		**1,087,565**	**1,089,134**

*US 15.8 million of borrowings reported as at 31 December 2023 has been reclassified from non-current to current as disclosed in Note 36. US 4.5 million of derivative financial liabilities instruments as at 31 December 2023 has been reclassified to trade and other payables as disclosed in Note 39 and Note 40.

Consolidated Statement of Changes in Equity for the year ended 31 December 2024

	Share capital USD'000	Share premium account USD'000	Merger reserve USD'000	Share-based payments reserve USD'000	Capital redemption reserve USD'000	Hedging reserve USD'000	Acc
As at 1 January 2023	339	983	146,270	26,907	21	-	
Loss for the year	-	-	-	-	-	-	
Other comprehensive income for the year	-	-	-	-	-	(14,131)	
Total comprehensive income for the year	**-**	**-**	**-**	**-**	**-**	**(14,131)**	
Share-based payments (Note 8)	-	-	-	766	-	-	
Shares issued (Note 29)	120	52,846	-	-	-	-	
Transaction costs associated with issuance of shares (Note 29)	-	(2,002)	-	-	-	-	
Share repurchased (Note 29)	(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**	**(14,131)**	

	Share capital USD'000	Share premium account USD'000	Merger reserve USD'000	Share-based payments reserve USD'000	Capital redemption reserve USD'000	Hedging reserve USD'000	Acc
As at 1 January 2024	456	51,827	146,270	27,673	24	(14,131)	
Loss for the year	-	-	-	-	-	-	
Other comprehensive income for the year	-	-	-	-	-	8,798	
Total comprehensive income for the year	**-**	**-**	**-**	**-**	**-**	**8,798**	
Share-based payments (Note 8)	-	-	-	407	-	-	
Shares issued (Note 29)	1	349	-	(350)	-	-	
Total transactions with owners, recognised directly in equity	**1**	**349**	**-**	**57**	**-**	**-**	
As at 31 December 2024	**457**	**52,176**	**146,270**	**27,730**	**24**	**(5,333)**	

Consolidated Statement of Cash Flows for the year ended 31 December 2024

	Notes	2024 USD'000	2023 USD'000
Operating activities			
Loss before tax		(43,435)	(102,766)
Adjustments for:			
Depletion, depreciation and amortisation	6	91,407	76,141
Share-based payments	7	407	766
Assets written off	10	1,775	5,114

	Notes	2024	2023
Allowance for slow moving inventories	10	1,670	655
Allowance for expected credit losses	10	457	-
Reversal of provision	13	(14,936)	(7,653)
Unrealised foreign exchange gain		(297)	(177)
Impairment of oil and gas properties	12	-	29,681
Interest income	13	(7,492)	(4,451)
Finance costs	14	45,134	41,829
Other financial gains	15	(2,611)	-
Share of results of associate	23	(1,553)	(2,640)
Operating cash flows before movements in working capital		**70,526**	**36,499**
Working capital movements:			
Increase in trade and other receivables		(63,613)	(80,900)
Increase in inventories		(29,954)	(15,655)
(Decrease)/Increase in trade and other payables		(39,623)	62,392
Cash (used in)/generated from operations		**(2,756)**	**2,336**
Net tax paid		(27,907)	(14,461)
Net cash used in operating activities		**(30,663)**	**(12,125)**
Investing activities			
Cash paid for acquisition of Sinphuhorm Assets	23	-	(27,853)
Cash received on acquisition of additional interest of CWLH Assets	18	5,236	-
Payment for oil and gas properties	20	(48,427)	(107,500)
Payment for plant and equipment	21	(476)	(516)
Payment for intangible exploration assets	19	(1,607)	(1,508)
Dividends received from associate	23	8,660	3,842
Interest received	13	7,492	4,451
Net cash used in investing activities		**(29,122)**	**(129,084)**

	Notes	2024 USD'000	2023 USD'000
Financing activities			
Net proceeds from issuance of shares	29	-	50,964
Shares repurchased	29	-	(2,084)
Total drawdown of borrowings	38	43,000	232,000
Repayment of borrowings	38	-	(75,000)
Interest on borrowings paid	38	(18,944)	(5,007)
Borrowings costs paid	38	-	(7,595)
Commitment fees of borrowings paid	38	(142)	(658)
Repayment of lease liabilities	38	(18,985)	(17,171)
Other interest and fees paid		(3,322)	(4,165)
Net cash generated from financing activities		**1,607**	**171,284**
Net (decrease)/increase in cash and cash equivalents		**(58,178)**	**30,075**
Cash and cash equivalents at beginning of the year		153,404	123,329
Cash and cash equivalents at end of the year	28	**95,226**	**153,404**

Notes to the Consolidated Financial Statements for the year ended 31 December 2024

1. CORPORATE INFORMATION

Jadestone Energy plc (the "Company" or "Jadestone") is a company incorporated and registered in England and Wales.The Company's shares are traded on AIM under the symbol "JSE". The Company is the ultimate parent company. The consolidated financial statements of the Company and its subsidiaries (the "Group") for the year ended 31 December 2024 were authorised for issue in accordance with a resolution of the directors on 19 May 2025.

The Group is engaged in production, development, exploration and appraisal activities in Australia, Malaysia, Vietnam, Indonesia and was engaged in Thailand for the year under review but disposed post year on 16 April 2025. 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 were in the Sinphuhorm gas field onshore north-east Thailand. On 31

July 2024, the Group commenced commercial production at the Akatara Gas Field located onshore Indonesia.

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

2. MATERIAL ACCOUNTING POLICY INFORMATION

BASIS OF PREPARATION

The financial statements have been prepared on the historical cost convention basis, except as disclosed in the accounting policies below and 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").

GOING CONCERN

The Directors have reviewed the Group's forecasts and projections, taking into account reasonably possible changes in trading performance and the current macroeconomic environment. Based on this assessment, the Directors have a reasonable expectation that the Group has adequate resources to continue in operational existence for the foreseeable future, which represents a period of at least 12 months from the date of approval of these financial statements (the "Review Period").

The assessment undertaken included applying appropriate estimates of future production, associated operating costs and committed capital expenditure. Consideration was also given to the potential impact of increased uncertainty and volatility caused by recent geopolitical events on global commodity markets and modelled through downside oil price sensitivities.

As of 31 December 2024, the Group had available liquidity of US 82.8 million in cash and cash equivalents, excluding restricted cash. As at 31 April 2025, the Group had available liquidity of approximately US 145.6 million, consisting of cash and cash equivalents (excluding restricted cash) of US 115.6 million and an undrawn working capital facility of US 30 million provided by an international bank with a 31 December 2026 maturity.

On 16 April 2025, the Group completed the sale of its 9.52% interest in the producing Sinphuhorm gas field for a cash consideration of US 39.4 million, with a further US 3.5 million in cash payable contingent on future license extensions. Funds received have been used to repay a portion of the outstanding debt under its Reserves Based Lending facility which, following the conclusion of the March 2025 redetermination, currently has a borrowing base[5] of US 167.0 million. The Group continues to maintain covenant compliance of 3.5x EBITDAX to net debt under the Reserve Based Lending ("RBL") facility with significant headroom. Based on current projections, the Group expects to remain compliant with all financial covenants throughout the going concern assessment period.

Capital expenditure guidance for 2025 remains at US 75 million to US 95 million, as previously disclosed, with the principal capital expenditure relating to the Skua-11ST well side-track program. Since the balance sheet date, Brent crude oil prices have fluctuated between US 61/bbl and US 83/bbl, whichremains within the Group's operating tolerances. The Group's financial modeling indicates that operations remain viable within this price range. Additionally, the Group has mitigated its exposure to oil price volatility by implementing a hedging strategy, with approximately 1.2 million barrels of oil hedged through the second and third quarters of 2025 at a weighted average price of US 68.6/bbl.

The Group closely monitors its cash, funding and liquidity position, with both near-term and longer-term cash projections and underlying assumptions reviewed and updated regularly to reflect operational and external conditions. The Group has conducted sensitivity analysis on its cash flow projections, including scenarios incorporating Brent oil prices modelled at US 60/bbl combined with additional unplanned downtime, being three separate events at Montara, CWLH and Akatara with each event lasting one month (three months in total), with deferral of capital expenditure and reduction in operating expenditure through the Review Period, and includes the borrowing base, as projected, for the six months following the redetermination in September 2025 of US 135 million and US 71 million for the six months from March 2026. Under these stressed scenarios, together with the projected borrowing base, the Group's liquidity position remains adequate to meet operational requirements and debt service obligations throughout the period. In addition, the Directors believe that there are additional courses of action available to the Group to create further liquidity, should that be required, including, but not limited to, the implementation of additional operating cost efficiencies and an amendment, extension or re-financing of the existing Reserves Based Lending facility.

The Directors have determined, at the time of approving the financial statements, that there is reasonable expectation the Group will continue as a going concern for the foreseeable future. Accordingly, they have prepared these audited consolidated financial statements on a going concern basis.

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.

Amendments to IAS 1	Non-current liabilities with Covenants
Amendments to IAS 1	Classification of Liabilities as Current of Non-current
Amendments to IAS 1	Classification of Liabilities as Current of Non-current Deferral of Effective Date
Amendments to IAS 7 and IFRS 7	Supplier Finance Arrangements
Amendments to IFRS 16	Lease liabilities in Sale and Leaseback

Non-current liabilities with Covenants
The Group has adopted the amendments to IAS 1, published in November 2022, for the first time in the current year. The amendments specify that only covenants that an entity is required to comply with on or before the end of the reporting period affect the entity's right to defer settlement of a liability for at least twelve months after the reporting date (and therefore must be considered in assessing the classification of the liability as current or non-current). Such covenants affect whether the right exists at the end of the reporting period, even if compliance with the covenant is assessed only after the reporting date (e.g. a covenant based on the entity's financial position at the reporting date that is assessed for compliance only after the reporting date). The IASB also specifies that the right to defer settlement of a liability for at

least twelve months after the reporting date is not affected if an entity only has to comply with a covenant after the reporting period. However, if the entity's right to defer settlement of a liability is subject to the entity complying with covenants within twelve months after the reporting period, an entity discloses information that enables users of financial statements to understand the risk of the liabilities becoming repayable within twelve months after the reporting period. This would include information about the covenants (including the nature of the covenants and when the entity is required to comply with them), the carrying amount of related liabilities and facts and circumstances, if any, that indicate that the entity may have difficulties complying with the covenants.

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:

Description	Effective for annual periods beginning
Amendments to IAS 21 Lack of exchangeability	1 January 2025
Amendments to IFRS 9 and IFRS 7 Contracts referencing nature-dependent electricity	1 January 2026
Annual improvements to IFRS accounting standards - Volume 11 (IFRS 10, IFRS 9, IFRS 1, IAS 7, IFRS 7)	1 January 2026
Amendments to IFRS 9 and IFRS 7 Amendments to the classification and measurement of financial instruments	1 January 2026
IFRS 18 Presentation and disclosure in financial statements	1 January 2027
IFRS 19 Subsidiaries without public accountability: disclosures	1 January 2027

The Directors do not expect that the adoption of the standards listed above will have a material impact on the financial statements of the group in future periods, except as indicated below.

IFRS 18 Presentation and Disclosures in Financial Statements

IFRS 18 replaces IAS 1, carrying forward many of the requirements in IAS 1 unchanged and complementing them with new requirements. IFRS 18 introduces new requirements to:

- present specified categories and defined subtotals in the statement of profit or loss;
- provide disclosures on management-defined performance measures (MPMs) in the notes to the financial statements;
- improve aggregation and disaggregation.

An entity is required to apply IFRS 18 for annual reporting periods beginning on or after 1 January 2027, with earlier application permitted. IFRS 18 requires retrospective application with specific transition provisions.

The directors of the company anticipate that the application of these amendments may have an impact on the presentation of the group's consolidated financial statements in future periods.

BASIS OF CONSOLIDATION

The consolidated financial statements incorporate the financial statements of the Company and all its subsidiaries made up to 31 December of each year.

The Group reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to the elements of control.

Consolidation of a subsidiary begins when the Group obtains control over the subsidiary and ceases when the Group loses control of the subsidiary. Specifically, the results of subsidiaries acquired or disposed of during the year are included in the consolidated financial statements from the date the Group gains control until the date when the Group 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.

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

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 are initially capitalised as E&E assets.

All such capitalised costs are subject to regular 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.

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. 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.

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. 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. 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 licenses, 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 licenses, 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 consist of interest and other costs that an entity incurs in connection with the borrowing of funds.

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.

PLANT AND EQUIPMENT

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

Depreciation is recognised so as to write off the cost of assets less their residual values using the straight-line method over their useful lives, on the following:

- Computer equipment: 3 years; and
- Fixtures and fittings: 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 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, to determine whether there is any indication that those assets have suffered an impairment loss. If any 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.

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.

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. An underlift of production from a field is included in current receivables and an overlift of production from a field is included in current liabilities.

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, except for trade receivables that do not have a significant financing component which are measured at transaction price. 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 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 recognises a loss allowance for expected credit losses on investments in debt instruments that are measured at amortised cost or at FVTOCI, lease receivables, trade receivables and contract assets, as well as on financial guarantee contracts. The amount of expected credit losses is updated at each reporting date to reflect changes in credit risk since initial recognition of the respective financial instrument.

The concentration of credit risk relates to the Group's single customer with respect to oil sales in Australia, a different single customer for oil and gas sales in Malaysia and a different single customer for gas in Indonesia. All customers have an 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 always recognises lifetime expected credit losses (ECL) for trade receivables, contract assets and lease receivables. The expected credit losses on these financial assets are estimated using a provision matrix based on the group's historical credit loss experience, adjusted for factors that are specific to the debtors, general economic conditions and an assessment of both the current as well as the forecast direction of conditions at the reporting date, including time value of money where appropriate.

For all other financial instruments, the group recognises lifetime ECL when there has been a significant increase in credit risk since initial recognition. However, if the credit risk on the financial instrument has not increased significantly since initial recognition, the group measures the loss allowance for that financial instrument at an amount equal to 12-month ECL.

Lifetime ECL represents the expected credit losses that will result from all possible default events over the expected life of a financial instrument. In contrast, 12-month ECL represents the portion of lifetime ECL that is expected to result from default events on a financial instrument that are possible within 12 months after the reporting date.

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).

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.

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 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

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. 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, 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 are 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

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 recognized 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 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 40 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 34.

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, 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 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. The discontinuation is accounted for prospectively. Any gain or loss recognised in other comprehensive, 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. The fair value determined at the grant date of the equity-settled share-based payments is expensed on a straight-line basis over the vesting period, based on the group's estimate of the number of equity instruments that will eventually vest. At each reporting date, the group revises its estimate of the number of equity instruments expected to vest as a result of the effect of non-market-based vesting conditions. 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 reserves.

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.

For cash-settled share-based payments, a liability is recognised for the goods or services acquired, measured initially at the fair value of the liability. At each reporting date until the liability is settled, and at the date of settlement, the fair value of the liability is remeasured, with any changes in fair value recognised in profit or loss for the year.

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 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 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. The depreciation starts at the commencement date of the lease. 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.

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 35.

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 profit or loss when performance obligations are considered met, which is when control of the hydrocarbons are transferred to the customer.

When (or as) a performance obligation is satisfied, the Group recognises as revenue the amount of consideration which it expects to be entitled to in exchange for transferring promised goods or services. Revenue is presented net of hedging loss as this deduction formed part of a contractual method for determining the transaction price. The net hedging loss is 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, in this case, revenue.

Revenue from the production of oil, liquified petroleum gas ("LPG"), condensate and 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 which includes oil, LGP and condensate are 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.

INCOME TAX

Income tax expense represents the sum of the current tax and deferred tax.

Current tax

The current tax is based on taxable profit or loss for the year which 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.

Indonesia Corporate and Dividend Tax (C&D)

C&D incurred in Indonesia is considered for accounting purposes to be a tax based on income derived from petroleum operations. Accordingly, C&D expense is measured and disclosed on the same basis as income tax.

C&D is calculated at the rate of 20% of sales revenues less certain permitted deductions and is tax deductible for income tax purposes. For Indonesian corporate tax purposes, C&D payment is treated as a deductible expense. Therefore, for the purposes of calculating deferred tax, the C&D tax rate is combined with the Indonesian corporate tax rate of 30% to derive a combined effective tax rate of 44%.

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. 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 or for transactions that give rise to equal taxable and deductible temporary differences) of other assets and liabilities in a transaction that affects neither the taxable profit nor the accounting profit. Deferred tax is 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, are only recognised to the extent that it is probable that there will be sufficient taxable profits against which to utilise. 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 are required to make judgments, estimates and assumptions about the carrying amounts of assets and liabilities. 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.

Most significant accounting judgments

The following are the 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 18.

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 in an pre-impairment charge of US 40.4 million and a 5% increase in the reserves estimates would result in an increase in the headroom above impairment. The Directors 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 and intangible exploration assets, 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 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 20, 21 and 22, 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 97 mb/d in 2022 to 78 mb/d by 2030 and 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.

Sensitivity analyses

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, ERCEs and approved by the Directors. The forecasted price assumptions are US 77.1/bbl in 2025, US 76.7/bbl in 2026, US 79.4/bbl in 2027, US 80.8/bbl in 2028 and an average of US 82.5/bbl from 2029 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 in an impairment charge of US 100.7 million and a 10% price increase in isolation would increase the current headroom without any negative impacts.

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 prices fall, upstream operating costs typically decrease as companies cut expenses and renegotiate contracts. Lower activity reduces demand for logistics, engineering, and project management services, leading to lower costs. Construction and labor costs also drop as spending slows, pushing down contractor rates and wages. Together, these factors drive an overall reduction in industry operating costs. 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% (2023: 5%) change to the post-tax discount rate used of 11.1% in Australia (Stag, Montara & CWLH), 12.8% in Malaysia (PenMal) and 14.0% in Indonesia (Akatara), (2023 Group: 10.50%) for impairment testing of oil and gas properties, and concluded that a 5% increase in the post-tax discount rate would result to an impairment charge of US 12.1 million and a 5% decrease in the post-tax discount rate would increase the headroom without any negative impact.

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:

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	>>2035
Brent	74.10	71.70	74.20	66.90	59.60	52.30	51.60	51.00	50.30	49.60	47.23*

*From 2035 this represents the average for the period 2035-2040.

Based on the analysis performed, the reduction in operating cash flows under the Net Zero Emissions by 2050 Scenario would result to in a pre-tax impairment charge of US 251.1 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 35 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 49.8 million and a 1% increase in discount rate would decrease the liability by US 45.0 million. A 1% increase in the inflation rate would increase the liability by US 49.9 million and a 1% decrease in inflation rate would decrease the liability by US 46.8 million. A 10% increase in current estimated costs would increase the liability by US 61.6 million and a 10% decrease in current estimated costs would decrease the liability by US 61.3 million. A one year deferral to the estimated decommissioning year of each asset as disclosed in Note 35 would decrease the liability by US 11.5 million and an acceleration of one year to the estimated decommissioning year as disclosed in Note 35 would increase the liability by US 8.0 million. The Directors 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.

d) Deferred tax assets

Deferred tax assets are recognised for all unutilised tax losses, unabsorbed capital allowances and unabsorbed reinvestment allowances to the extent that it is probable that taxable profit will be available against which it can be utilised. Significant management judgement is required to determine the amount of deferred tax assets that can be recognised, based on the likely timing and level of future taxable profits together with future tax planning strategies. If the Group were able to recognise all unrecognised deferred tax assets, the profit would increase by US 10.9 million. The amount of recognised are disclosed in Note 25.

4. REVENUE

The Group presently derives its revenue from contracts with customers for the sale of hydrocarbon products including oil, gas, condensate and LPG.

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

	2024 USD'000	2023 USD'000
Liquids revenue	405,964	317,469
Hedging loss (Note 34 and Note 40)	(27,417)	(10,322)

	378,547	**307,147**
Gas revenue	7,962	2,053
LPG revenue	4,313	-
Condensate revenue	4,214	-
	395,036	**309,200**

As required under the RBL as disclosed in note 36, the Group entered into commodity swap contracts to hedge approximately 50% of its forecasted planned liquids production from October 2023 to September 2025. The commodity swap contracts were measured using hedge accounting. See Note 40 for the details of the commodity swap contracts.

On 31 July 2024, the Group successfully commenced operations of the Akatara Gas Processing Facility ("Akatara Facility") producing gas, liquefied petroleum gas ("LPG"), and condensate.

5. PRODUCTION COSTS

	2024 USD'000	2023 USD'000
Operating costs	129,078	114,779
Workovers	20,797	17,562
Logistics	26,928	34,109
Repairs and maintenance	70,304	55,572
Tariffs and transportation costs	8,451	7,502
Decommissioning expenses	-	12,545
Underlift and overlift and crude inventories movement	21,411	(9,297)
	276,969	**232,772**

Operating costs predominately consist of offshore manpower costs of US 30.6 million (2023: US 26.0 million), chemicals, services, supplies and other production related costs for a total of US 40.0 million (2023: US 49.3 million), Malaysian supplementary payments totalled US 6.8 million (2023: US 10.5 million), CWLH Asset royalties of US 6.7 million (2023: US 3.5 million), Montara royalties of US 2.5 million (2023: US 1.7 million), insurance of US 5.3 million (2023: US 4.9 million) and non-operated assets production costs of US 31.3 million (2023: US 16.0 million). The Malaysian supplementary payments are payable under the terms of PSCs based on the Group's entitlement to profit from oil and gas.

The crude inventories movements represent the net movement of crude inventories at year end against beginning of the year which represent the production cost excluding the depletion expenses portion as disclosed in Note 6. The underlift, overlift and crude inventories movements resulted in and expenses of US 21.4 million (2023: credit of US 9.3 million charge), which mostly related to US 40.6 million of expense subsequent to lifting associated with the acquisition of the second tranche of the CWLH Asset. The acquisition included 530,484 bbls of underlift at closing at a fair market valuation of US 86.27/bbl, less 10% royalties and approximately 1% in selling fees, totalling US 40.6 million as disclosed on Note 18. The inventory was sold in March 2024. At year end, CWLH is in underlift position of 386,451 bbls and accordingly has recognised a credit of US 18.1 million.

Workovers in 2024 and 2023 were recurring in nature. The Group carried out a higher number of workovers at Stag in 2024 in comparison of 2023.

Repairs and maintenance in current year include rectification costs of the cranes and platform of AAKBNLP asset at PenMal, subsea maintenance at Montara and fabric maintenance costs at Stag. In 2023, the costs included storage tank repairs, FPSO ("Floating, Production Storage and Offloading") maintenance and fabric maintenance costs at both Montara and Stag.

In 2023, the Group incurred US 12.5 million in decommissioning expenses related to its non-operated interest in the FPSO at the PNLP Asset before the previous operator departure.

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

	2024 USD'000	2023 USD'000
Depletion and amortisation (Note 20)	77,187	64,575
Depreciation of:		
Plant and equipment (Note 21)	555	494
Right-of-use assets (Note 22)	16,195	15,251
Crude inventories movement	(2,530)	(4,179)
	91,407	**76,141**

The crude inventories movement represents a 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.

7. ADMINISTRATIVE STAFF COSTS

	2024	2023

	USD'000	USD'000
Wages, salaries and fees	28,985	24,729
Staff benefits in kind	5,031	4,702
Share-based compensation (Note 32)	407	766
	34,423	**30,197**

The compensations of Directors and key management personnel are included in the above and disclosed separately in Notes 9 and 47, respectively.

8. STAFF NUMBERS AND COSTS

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

	2024 Number	2023 Number
Production	159	162
Technical	254	238
Management	9	9
	422	**409**

Staff costs are split between production costs (Note 5) for offshore personnel and administrative staff costs (Note 7) for onshore personnel. Administrative staff costs comprise all onshore personnel at each of the respective offices, covering roles that support the offshore operations and administrative functions.

Their aggregate remuneration comprised:

	2024 USD'000	2023 Reclassified* USD'000
Wages and salaries	51,750	44,343
Fees	701	767
Staff benefits in kind	3,697	3,270
Social security costs	233	180
Defined contribution pension costs	3,251	3,149
Share-based compensation (Note 32)	407	766
	60,039	**52,475**
Contractors and consultants costs	5,011	3,704
	65,050	**56,179**

*In 2024, management has applied a new categorisation for fees and benefits in kind compared to the prior year's disclosure. As a result, prior year figures for wages and salaries, social security costs, defined contribution pension costs, and contractor and consultant costs have been reclassified accordingly.

9. DIRECTORS' REMUNERATION AND TRANSACTIONS

	2024 USD'000	2023 USD'000
Directors' remuneration		
Salaries, fees, bonuses and benefits in kind	2,620	2,496
Amounts receivable under long term incentive plans	233	300
Money purchase pension contributions	87	102
Compensation for loss of office	2,464[a]	-
	5,404	**2,898**

	Number	Number
The number of Directors who:		
Are members of a money purchase pension scheme	2	2
Had awards receivable in the form of shares under a long-term incentive scheme	4	2

[a] Compensation for loss of office amounting to US 2.3 million, including US 0.2 million of payroll tax for A. Paul Blakeley.

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

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

For further details and details of remuneration of the highest paid director, please refer to Note 47.

10. OTHER EXPENSES AND ALLOWANCE FOR EXPECTED CREDIT LOSSSES

	2024 USD'000	2023 USD'000
Corporate costs	13,962	14,179
Allowance for slow moving inventories	1,670	655
Assets written off	1,775	5,114
Net foreign exchange loss	2,008	1,728
Other expenses	4,444	1,165
	23,859	**22,841**

	2024 USD'000	2023 USD'000
Allowance for expected credit losses (Note 27)	457	-
	457	**-**

Corporate costs include recurring general and administration expenses such as professional fees, office and travelling costs of US 12.5 million (2023: US 10.5 million) and non-recurring costs such as business development costs of US 0.9 million (2023: US 2.2 million), professional fees in relation to internal reorganisation of US 0.1 million (2023: US 0.8 million), equity fundraising of US Nil (2023: US 0.4 million) and external funding sourcing of US 0.5 million (2023: US 0.2 million).

Assets written off in 2024 represent the derecognition of US 1.4 million of Montara non-depletable oil and gas properties following capitalisation of replacement parts and US 0.4 million of obsolete materials and spares. In 2023, write-offs included US 3.1 million for Montara non-depletable oil and gas properties following the cancellation of the Skua-12 well development capital project, as well as US 2.0 million for obsolete materials and spares.

Other expenses mainly consist of US 1.5 million of expenses of dividend based royalties from Sinphuhorm gas field and another US 1.3 million related to withholding taxes expenses.

11. AUDITOR'S REMUNERATION

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

	2024 USD'000	2023 USD'000
Fees payable to the Company's auditor for the audit of the parent company and Group's consolidated financial statements	668	600
Audit fees of the subsidiaries	519	417
	1,187	**1,017**

No fee was paid to the Group's auditor for non-audit services for either the Group or the Company in 2023 or 2024.

12. IMPAIRMENT OF ASSETS

	2024 USD'000	2023 USD'000
Impairment of oil and gas properties (Note 20)	-	29,681

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 was made following the annual impairment assessment performed by the Directors which identified that the VIU ("Value in Use') of the operating asset, determined based on the post-tax discount rate used of 10.5%, was 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 was made in relation to the producing asset of the Group located in Australia as disclosed in Note 43. There is no impairment noted in 2024.

Additionally in 2023, the Group also provided impairment of US 12.3 million associated with the adjustment to the ARO estimates for the PNLP Assets (Note 35) that underwent retendering during the year after ceasing production in 2022, following the class suspension of the FPSO. The revision of ARO estimates reflects the change in assumptions used for the estimation of the decommissioning costs.

13. OTHER INCOME

	2024 USD'000	2023 USD'000
Interest income	7,492	4,451
Reversal of provisions:		
Lemang PSC contingent payments (Note 35)	-	7,653
Asset restoration obligations (Note 20 and Note 35)	13,824	-
Others (Note 35)	1,112	-
Net foreign exchange gain	921	322
Rental income	5,731	6,375
Sundry income	534	54
	29,614	**18,855**

14. FINANCE COSTS

	2024 USD'000	2023 USD'000
Interest expense:		
Lease liabilities	2,465	2,771
Standby working facility (Note 36)	1,483	953
RBL facility (Note 36)	16,428	8,089*
Others	178	138*
Accretion expense for:		
Asset restoration obligations (Note 35)	22,544	20,201
Non-current Lemang PSC VAT receivables	180	1,182
Fair value loss on warrants (Note 41)	-	3,469
Upfront fees on financing facilities	867	2,656
Changes in fair value of:		
Lemang PSC contingent payments (Note 35)	53	868
CWLH Assets contingent payment (Note 35)	-	60
RBL commitment fees (Note 36)	142	349
Fair value loss on derivative liability (Note 40)	-	73
Other finance costs	794	1,020
	45,134	**41,829**

* We have reclassified the categorisation of interest expenses of US 2.7 million and RBL accretion expenses of US 5.5 million in 2023 to interest expenses on RBL facility of US 8.1 million and interest expenses on others of US 0.1 million.

15. OTHER FINANCIAL GAINS

	2024 USD'000	2023 USD'000
Fair value gain on warrants (Note 41)	2,538	-
Fair value gain on derivative liability	73	-
	2,611	**-**

16. INCOME TAX EXPENSE/(CREDIT)

	2024 USD'000	2023 USD'000
Current tax		
Corporate tax charge/(credit)	1,066	(3,403)
(Over)/underprovision in prior years	(468)	2,051
	598	**(1,352)**
Australian petroleum resource rent tax ("PRRT")	(1,700)	1,735
Malaysian petroleum income tax ("PITA")	8,275	10,377
	7,173	**10,760**
Deferred tax		
Corporate tax	(1,548)	(20,138)
Underprovision of deferred tax in prior years	(361)	-
	(1,909)	**(20,138)**
PRRT	(10,031)	(4,269)

PITA	5,473	2,155
	(6,467)	**(22,252)**
	706	**(11,492)**

On 23 May 2023, the International Accounting Standards Board issued International Tax Reform - Pillar Two Model Rules - Amendments to IAS 12 which clarify that IAS 12 applies to income taxes arising from tax law enacted or substantively enacted to implement the Pillar Two model rules published by the Organisation for Economic Co-operation and Development ("OECD"), including tax law that implements Qualified Domestic Minimum Top-up Taxes. The Group has adopted these amendments. However, they are not yet applicable for the current reporting year as the Group's consolidated revenue is currently below the threshold of €750.0 million.

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 4.1 billion (2023: US 3.8 billion) and US 802.4 million (2023: US 493.4 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 11.7 million (2023: expense of US 2.5 million).

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 13.7 million during the year (2023: US 12.5 million).

The Indonesia corporate income tax rate is applied at 30% of Indonesia corporate taxable income. Corporate and Dividend Tax ("C&D") is calculated at 20% of sales revenue less certain permitted deductions and is tax deductible for Indonesia corporate income tax purposes. There is no tax expense during the year for Indonesia tax due to the Lemang asset as it is not in a taxable income position.

The tax recoverable of US 13.8million (2023: US 4.1 million) as at year end includes a PITA receivable of US 3.9 million (2023: US 3.9 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 differs from the amount that would arise using the standard rate of income tax applicable in the countries of operation as explained below:

	2024 USD'000	**2023 USD'000**
Loss before tax	**(43,435)**	**(102,766)**
Tax calculated at the domestic tax rates applicable to the profit/loss in the respective countries (Australia 30%, Malaysia 24% & 38%, Canada 27%, Singapore 17% and Indonesia 30%)	(10,323)	(27,543)
Effects of non-deductible expenses	839	4,003
Income not subject to tax	(1,897)	-
Effect of PRRT/PITA tax expense	6,575	12,112
Deferred PRRT/PITA tax (credit)/expense	(4,558)	(2,115)
Deferred tax assets not recognised	10,899	-
(Over)/underprovision of current tax in prior years	(468)	2,051
Underprovision of deferred tax in prior years	(361)	-
Tax expense/(credit) for the year	**706**	**(11,492)**

Deferred tax assets amounting of US 10.9 million (2023: US Nil) have not been recognised in respect of these losses as they may not be used to offset taxable profits elsewhere in the Group, they have arisen in subsidiaries that have been loss-making for some time, and there are no other tax planning opportunities or other evidence of recoverability in the near future. Unrecognised deferred tax assets during the year amount to US 10.9 million.

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

	2024 USD'000	**2023 USD'000**
Other comprehensive income - deferred tax		
Income tax expense/(credit) related to carrying amount of hedged item	**3,770**	**(6,056)**

17. LOSS PER ORDINARY SHARE

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

	2024 USD'000	2023 USD'000
Loss for the purposes of basic and diluted per share, being the net loss for the year attributable to equity holders of the Company	(44,141)	(91,274)

	2024 Number	2023 Number
Weighted average number of ordinary shares for the purposes of basic EPS	540,848,891	499,480,437
Weighted average number of ordinary shares for the purposes of dilutive EPS	**540,848,891**	**499,480,437**

In 2024, 47,139 (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 2024, 53,106 (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 2024, 293,655 (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 2024, 30,000,000 (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 per share (US)	**2024**	**2023**
- Basic and diluted	(0.08)	(0.18)

18. ACQUISITIONS

18.1 ACQUISTION OF INTEREST IN CWLH JOINT OPERATION

a. Effective date and Acquisition date

On 14 November 2023, the Group executed a sale and purchase agreement ("SPA") with Japan Australia LNG (MIMI) Pty Ltd ("MIMI"or "Seller") to acquire MIMI'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 9.0 million.

In addition to the total consideration and as part of this transaction, the Group was required to pay 16.67% of the participating interest share of the abandonment amount based on the operator's estimate into a decommissioning trust fund administered by the operator of the CWLH Assets. The first tranche of US 42.0 million was paid on closing of the acquisition in February 2024 and a second instalment of US 23.0 million was transferred after the approval by the Offshore Petroleum & Greenhouse Gas Storage Act (2006) title registration in April 2024. In July 2024, the operator confirmed the final payment of US 18.8 million, and this was paid in December 2024. For the purpose of cash flow, this is disclosed within the working capital of trade and other receivables movement.

The acquisition completed on 14 February 2024. The acquisition has an economic effective date of 1 July 2022, which meant the Group was entitled to net cash generated since effective date to completion date, resulting in a cash receipt of US 5.2 million at completion. On 14 May 2024, 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, 14 February 2024 (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.

b. Acquisition of a 16.67% non-operated working interest

The CWLH Assets contain inputs (working interest in the CWLH Assets) and processes (existing 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.

c. Fair value of consideration

After taking into account various adjustments the net consideration for the CWLH Assets resulted in a cash receipt of US 5.2 million, as set out below:

	USD'000
Asset purchase price	9,000

Asset purchase price	9,000
Closing statement adjustments[6]	(14,236)
Net cash receipts from the acquisition	**(5,236)**

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 seller 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 Seller 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 Seller. Both parties had engaged their own professional advisors. There is no reason to conclude that the transaction was not transacted at arm's length.

d. 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 value of the net assets acquired within 12 months from the acquisition date. The fair value of the identifiable assets and liabilities have been reflected in the financial statements as at 31 December 2024.

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

	PPA USD'000
Asset	
Non-current asset	
Oil and gas properties (Note 20)	118
Deferred tax assets	19,763
Current asset	
Amount due from joint arrangement partner	194
Trade and other receivables	40,602*
	60,677

	PPA USD'000
Liabilities	
Non-current liabilities	
Provision for asset restoration obligations (Note 35)	65,881
Deferred tax liabilities	32
	65,913
Net identifiable liabilities assumed	**(5,236)**

* Trade and other receivables consisted of a gross underlift position of 530,484 bbls acquired by the Group, with a fair value of US 40.6 million, measured at the market price as at closing based on the February 2024 market value of US 86.27/bbl, less royalties and selling fees. The underlift position was recognised as an expense in production cost, following a lifting which occurred in March 2024.

e. Impact of acquisition on the results of the Group

The Group's 2024 results included US 56.4 million of revenue and US 2.0 million of after tax loss attributable to the acquisition of 16.67% of CWLH Assets.

Acquisition-related costs amounting to US 0.1 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 2024 and based on the performance of the business during 2023 under the Seller, the Group would have generated revenues of US 56.4 million and an estimated net profit after tax of US 40.6 million. As at acquisition date, there was an underlift position of 530,484 bbls acquired by the Group recognised at fair value of US 40.6 million. This amount is subsequently recognised as an expense in production cost upon lifting in March 2024, which causes the contribution to the group upon acquisition of US 2.0 million after tax loss.

18.2 ACQUISITION OF THE REMAINING 50% INTEREST IN THE PNLP ASSETS

a. 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 licenses. 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.

b. Asset acquisition

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.

c. 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 27)	28,176
	28,176
Liabilities	
Non-current liabilities	
Provision for asset restoration obligations (Note 35)	48,430
	48,430
Net identifiable liabilities assumed	**(20,254)**

19. INTANGIBLE EXPLORATION ASSETS

	USD'000
Cost	
As at 1 January 2023	77,928
Additions	1,636[b]
As at 31 December 2023	**79,564**
Additions	11,759[a][b]
As at 31 December 2024	**91,323**
Impairment	
As at 1 January 2023, 31 December 2023 and 31 December 2024	-
Carrying amount	
As at 31 December 2023	**79,564**
As at 31 December 2024	**91,323**

[a] Additions during the year includes of US 10.0 million arising from provision for commitment to drill one exploration well in Nam Du gas field in Block 46/07. For further information, please refer to Note 35.

[b] For the purpose of the consolidated statement of cash flows, current year expenditure on intangible exploration assets of US 10.2 million remained unpaid as at 31 December 2024 (2023: US 0.1 million).

20. OIL AND GAS PROPERTIES

	Production assets USD'000	Development assets USD'000	Total USD'000
Cost			
As at 1 January 2023	693,458	36,935	730,393
Changes in asset restoration obligations (Note 35)	3,133	4,017	7,150[a]
Additions	32,058	81,672	113,730[b]
Transfer of 50% interest in PNLP Assets	48,430	-	48,430
Written off	(3,067)	-	(3,067)
As at 31 December 2023	**774,012**	**122,624**	**896,636**
Changes in asset restoration obligations (Note 35)	(20,025)	1,330	(18,695)[a]
Additions	19,281	42,943	62,224[b]

Acquisition of additional interest of CWLH Assets (Note 18)	118	-	118
Written off	(2,965)	-	(2,965)
Reclassification	166,897[c]	(166,897)[c]	-
As at 31 December 2024	**937,318**	**-**	**937,318**
Accumulated depletion, amortisation and impairment			
As at 1 January 2023	296,748	-	296,748
Charge for the year (Note 6)	64,575	-	64,575
Impairment	78,111	-	78,111[d]
As at 31 December 2023	**439,434**	**-**	**439,434**
Charge for the year (Note 6)	77,187	-	77,187
Written off	(1,542)	-	(1,542)
As at 31 December 2024	**515,079**	**-**	**515,079**
Carrying amount			
As at 31 December 2023	**334,578**	**122,624**	**457,202**
As at 31 December 2024	**422,239**	**-**	**422,239**

[a] The changes in ARO in Note 35 of US 32.5 million includes the capitalisation in oil and gas properties of US 18.7million and recognition in other income of US 13.8 million in Note 13.

In 2023, the changes in ARO in Note 35 of US 19.4 million includes the increase in ARO of the PNLP Assets of US 24.6 million of which US 12.3 million is capitalised in this note representing 50% of the working interests owned by the Group. The remaining 50% of US 12.3 million is offset against the non-current other payable (Note 39) due to the costs that are to be funded from the cash advances receivable from the Malaysian joint arrangement partner.

[b] For the purpose of the consolidated statement of cash flows, current year expenditure on oil and gas properties of US 8.7 million remained unpaid as at 31 December 2024 (2023: US 3.8 million). The additions includes the capitalisation of borrowing costs of US 5.1 million (2023: US 2.4 million).

[c] On 31 July 2024, the Group successfully commenced operations of the Akatara Gas Processing Facility ("Akatara Facility") producing gas, LPG , and condensate.

[d] In 2023, the Group 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 39) 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[7] 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 bid was submitted in January 2024, with result of the bidding was successful on June 2024. The Group has been awarded the Puteri Cluster PSC as the operator holding 100% participating interest in the PSC, with 1 July 2024 as the effective date, being the date the PSC was officially signed between Malaysia regulator and the Group. With this effect, the PNLP Assets is deemed relinquished as at 30 June 2024 as disclosed in Note 24.

The remaining impairment amount in the prior year 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.

21. 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 2023	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**
Additions	446	30	-	476
Transfer		-	208	208[a]
As at 31 December 2024	**4,171**	**1,975**	**9,366**	**15,512**
Accumulated depreciation				
As at 1 January 2023	2,308	1,564	-	3,872

Charge for the year (Note 6)	347	147	-	494
As at 31 December 2023	**2,655**	**1,711**	**-**	**4,366**
Charge for the year (Note 6)	429	126	-	555
As at 31 December 2024	**3,084**	**1,837**	**-**	**4,921**
Carrying amount				
As at 31 December 2023	**1,070**	**234**	**9,158**	**10,462**
As at 31 December 2024	**1,087**	**138**	**9,366**	**10,591**

(a) 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 0.5 million (2023: US 1.7 million).

22. RIGHT-OF-USE ASSETS

	Transportation and logistics USD'000	Buildings USD'000	Total USD'000
Cost			
As at 1 January 2023	**46,100**	**3,643**	**49,743**
Additions	36,926	1,231	38,157
Derecognition	(39,673)	-	(39,673)
As at 31 December 2023	**43,353**	**4,874**	**48,227**
Additions	1,122	85	1,207
Derecognition	(5,117)	-	(5,117)
As at 31 December 2024	**39,358**	**4,959**	**44,317**
Accumulated depreciation			
As at 1 January 2023	**39,486**	**2,064**	**41,550**
Charge for the year (Note 6)	14,390	861	15,251
Derecognition	(39,673)	-	(39,673)
As at 31 December 2023	**14,203**	**2,925**	**17,128**
Charge for the year (Note 6)	15,297	898	16,195
Derecognition	(5,117)	-	(5,117)
As at 31 December 2024	**24,383**	**3,823**	**28,206**
Carrying amount			
As at 31 December 2023	**29,150**	**1,949**	**31,099**
As at 31 December 2024	**14,975**	**1,136**	**16,111**

Most of the Group's right-of-use assets are contracts to lease assets including helicopters, a supply boat and logistic facilities for the Montara field and buildings. The average lease term is 2.8 years (2023: 2.7 years). The additions to right-of-use assets during the year mainly consist of the extension on of the transportation and logistic assets.

The maturity analysis of lease liabilities is presented in Note 37.

	2024 USD'000	2023 USD'000
Amount recognised in profit or loss		
Depreciation expense on right-of-use assets (Note 6)	16,195	15,251
Interest expense on lease liabilities (Note 14)	2,465	2,771
Expenses relating to short-term leases	31,451	36,680
Expense relating to leases of low value assets	292	44

As at 31 December 2024, the Group is committed to US 6.3 million million (2023: US 3.9 million) of short-term leases.

The total cash outflow in 2024 relating to leases was US 50.7 million (2023: US 53.9 million).

23. INVESTMENT IN ASSOCIATE

	2024 USD'000	2023 USD'000
At beginning of year	26,651	-
Acquisition of 9.52% non-operated interest in Sinphuhorm Assets	-	27,853
Dividends received during the year	(8,660)	(3,842)
Share of profit of the associate	1,553	2,640
At end of year	**19,544**	**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 through APICO LLC. The acquisition included a 27.2% interest in APICO LLC, which operates the Sinphuhorm concessions (E5N and EU1) and Dong Mun (L27/43).

The Group accounts for its investment in APICO LLC using the equity method. The group has significant influence over APICO LLC by having the power to participate in the financial and operating policy decisions of the entity. As a result, the Group has an effective 9.52% non-operated interest in the Sinphuhorm gas field through its investment in APICO LLC.

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 APICO LLPs' financial statements which holds a 35% interest in the Sinphuhorm gas field. APICO LLC's financial statements are prepared in accordance with IFRS Accounting Standards.

	2024 USD'000	**2023 USD'000**
Current assets	46,414	39,027
Non-current assets	108,686	133,037
Current liabilities	34,665	27,048
Non-current liabilities	6,612	6,902
Revenue	85,775	59,504
Profit before tax	45,639	26,412
Profit after tax, representing total comprehensive income for the year	5,708	9,705
Proportion of the Group's ownership interest in the associate	27.2%	27.2%
Share of profit of the associate	1,553	2,640
Dividends received from the associate during the year	(8,660)	(3,842)

On 16 April 2025, the Group entered into a sale and purchase agreement with PTT Exploration and Production Public Company limited ("PTTEP") to sell Jadestone Energy (Thailand) Pte Ltd, Jadestone Energy (PHT GP) Limited and PHT Partners LP who collectively hold the effective 9.52% working interest on the Sinphuhorm gas field via its 27.2% interest in the Dong Mun gas discovery onshore north-east Thailand through APICO LLC. For further details, please refer to Note 46.

24. INTERESTS IN OPERATIONS

Details of the operations, of which all are in production except for 46/07, 51, Puteri Cluster and PM428 which are in the exploration stage, are as follows:

Contract Area	**Date of expiry**	**Held by**	**Place of operations**	**Group effective working interest % as at 31 December[c] 2024**	**2023**
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[a]	30 June 2024	Jadestone Energy (PM) Inc.	Malaysia	-	100
AAKBNLP[a]	30 June 2024	Jadestone Energy (PM) Inc.	Malaysia	-	100
Puteri Cluster SFA[a]	30 June 2038	Jadestone Energy (PM) Inc.	Malaysia	100	100
PM428	21 April 2053	Jadestone Energy (PM) Inc.	Malaysia	100	-
WA-3-L	Indefinite	Jadestone Energy (CWLH) Pty Ltd	Australia	33	17
WA-9-L	15 July 2033	Jadestone Energy (CWLH) Pty Ltd	Australia	33	17
WA-11-L	4 September 2035	Jadestone Energy (CWLH) Pty Ltd	Australia	33	17
WA-16-L	11 September 2039	Jadestone Energy (CWLH) Pty Ltd	Australia	33	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 concession (E5N)[b]	15 March 2031	Jadestone Energy (Thailand) Pte Ltd	Thailand	10	10

(E5N)[(b)]					
Sinphuhorm concessions (EU1)[(b)]	2 June 2029	Jadestone Energy (Thailand) Pte Ltd	Thailand	10	10
Dong Mun (L27/43)[(b)]	24 September 2017	Jadestone Energy (Thailand) Pte Ltd	Singapore	27	27

[(a)] The Group has been awarded the Puteri Cluster Small Field Assets ("SFA") as the operator holding 100% participating interest in the PSC, with 1 July 2024 as the effective date, being the date the PSC was officially signed between Malaysia regulator and the Group. With this effect, the PM318 and AAKBNLP Assets is deemed relinquished as at 30 June 2024. The decommissioning work is set to commence in 2038, hence both the receivable and provision relating to Putri Cluster has been reclassified from current to non-current as disclosed in Note 27 and Note 35.

[(b)] The Group entered intoa sale and purchase agreement to sell Jadestone Energy (Thailand) Pte Ltd and its interest in the Sinphuhorm gas fields as further disclosed in Note 23 and Note 46.

[(c)] The Group's effective working interest percentage as at 31 December reflects its share of participation in each asset, based on contractual arrangements in place at the reporting date. These percentages are used to determine the Group's proportionate recognition of related financial statement items.

25. 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 2023	**1,313**	**1,605**	**(70,281)**	**-**	**(67,363)**
Credited/(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 and 1 January 2024	**5,582**	**(550)**	**(50,143)**	**6,056**	**(39,055)**
Credited/(charged) to profit or loss (Note 16)	10,031	(5,473)	1,909	-	6,467
Credited to OCI	-	-	-	(3,770)	(3,770)
Acquisition of additional interest of CWLH Assets (Note 18)	-	-	19,731	-	19,731
Reclassification of carried forward business losses	-	-	1,905	-	1,905
As at 31 December 2024	**15,613**	**(6,023)**	**(26,598)**	**2,286**	**(14,722)**

The following is the analysis of the deferred tax balances (after offset)[8] for financial reporting purposes:

	31 December 2024 USD'000	31 December 2023 USD'000
Deferred tax liabilities	(59,620)	(65,829)
Deferred tax assets	44,898	26,774
	(14,722)	**(39,055)**

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.

There is no deferred tax asset recognised at Akatara due to the structure of the PSC and its cost recovery mechanism. Under the PSC terms, operating losses carried forward are recovered directly through the cost recovery process rather than through future tax savings. Since acquiring the Lemang PSC in 2020, accumulated losses have been added to the cost recovery pool, which will be reimbursed from future production entitlements.

As of first gas on 1 July 2024, the cost recovery pool stood at US 288.0 million. These historical losses are recovered through production which is not taxable until the cost recovery pool is fully depleted. The PSC will only generate income tax after the cost recovery pool is fully depleted and so there is not sufficient certainty that future profits will be generated against which to utilise the losses.

The Group has unutilised PRRT credits of approximately US 4.1 billion (2023: US 3.8 billion) and US 802.4 million (2023: US 493.4 million) 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 license of Montara and the CWLH Assets. No deferred tax asset has been recognised in respect of these PRRT credits, due to theDirectors' 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 4.1 billion (2023: US 3.8 billion) and US 802.4million (2023: US 493.4 million) with respect to Montara and the CWLH Assets are not expected to be utilised and are therefore not recognised as a deferred tax asset.

26. INVENTORIES

	2024 USD'000	2023 USD'000
Materials and spares	30,164	23,242
Less: allowance for slow moving	(9,960)	(7,010)
	20,204	**16,232**
Crude oil inventories	24,398	17,422
	44,602	**33,654**

The cost of inventories of US 323.0 million (2023: US 270.4 million) recognised as an expense during the year for lifted volume, is calculated by including production costs excluding workovers, Malaysian supplementary payments and tariffs and transportation costs, plus depletion expense of oil and gas properties, and plus depreciation of right-of-use assets deployed for operational use.

27. TRADE AND OTHER RECEIVABLES

	2024 USD'000	2023 USD'000
Current assets		
Trade receivables	15,846	12,533
Prepayments	8,459	5,947
Other receivables	7,731	88,005
Amount due from joint arrangement partners (net)	2,390	12,911
Underlift crude oil inventories	12,278	3,539
GST/VAT receivables	8,797	1,444
	55,501	124,379
Allowance for expected credit loss (Note 10)	(457)	-
	55,044	**124,379**
Non-current assets		
Other receivables	261,517	127,730
GST/VAT receivables	12,607	14,130
	274,124	**141,860**
	329,168	**266,239**

Set out below is the movement in the allowance for expected credit losses of trade receivables:

	2024 USD'000
As at 1 January 2024	
Allowance for expected credit losses (Note 10)	457
As at 31 December 2024	**457**

Trade receivables arise from revenues generated from operations in Australia, Malaysia and Indonesia. The average credit period is 30 days (2023: 30 days). The Group has recognised an allowance for expected credit losses of US 0.5 million and remaining outstanding receivables as at 31 December 2024 and 2023 have been recovered in full in 2025 and 2024, respectively.

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 2025.

The underlift crude oil inventories represent entitlement imbalances at year end of 9,950 bbls and 386,451 bbls at the PenMal operated assets and CWLH Asset measured at cost of US 17.34/bbl and US 31.32/bbl respectively. The 2024 underlift position will unwind in 2025 based on the subsequent net productions entitled to the Group. The Group was in underlift position at 2023 year end which unwound in 2024 based on actual production entitlement during the year.

The current other receivables in 2023 represent the accumulated amount due from a joint arrangement partner of Penmal PNLP Assets for its share of future wells preservation activities and decommissioning costs when it exited two PSC licenses during 2023. Subsequently in 2024, the Puteri Cluster cess fund of US 47.8 million has been reclassified to non-current as further disclosed in Note 24.

Non-current other receivables represent the accumulated cess payment paid to the Malaysian and Indonesian regulators for the operated licenses 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.

In 2023, 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 2024, the increase of non-current other receivables due to the abandonment trust fund payments which was required under acquisition of additional interest in CWLH Assets as disclosed in Note 18 and the reclassification of Puteri Cluster cess fund of US 47.8 million from current to non-current as disclosed in Note 24.

There are no trade receivables older than 30 days apart from those that have recognised an allowance for expected credit losses. The credit risk associated with the trade receivables is disclosed in Note 42.

28. CASH AND BANK BALANCES

	2024 USD'000	2023 USD'000
Cash and bank balances, representing cash and cash equivalents in the consolidated statement of cash flows, presented as:		
Non-current	888	1,008
Current	94,338	152,396
	95,226	**153,404**

The non-current cash and cash equivalents represents the restricted cash balance of US 0.6 million (2023: US 0.7 million) and US 0.3 million (2023: 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 deposits place for bank guarantees are expected to be in place for a period of more than twelve months, but allows withdrawal on demand within three months without penalty as at 31 December 2024.

Current cash and cash equivalents include a bank guarantee of US 0.3 million (2023: US 0.5 million) and US 3.0 million (2023: US Nil) placed by the Group during the year with respect to the construction of the Lemang PSC gas pipeline facilities and PenMal Asset. These deposits place for bank guarantees are expected to be in place for a period of less than twelve months, but allows withdrawal on demand within three months without penalty as at 31 December 2024.

As part of the RBL facility as disclosed in Note 36, 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"). As at 31 December 2024, the DSRA contained US 8.2 million (2023: US 8.2 million) in advance of the interest payable in March 2025.

29. 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 2023, at £0.001 each	448,353,663	339	983
Issued during the year	94,463,933	120	50,844
Shares repurchased	(2,051,022)	(3)	-
As at 31 December 2023	**540,766,574**	**456**	**51,827**
Issued during the year (Note 32)	344,225	1	349
As at 31 December 2024	**541,110,799**	**457**	**52,176**

During the year, no employee share options were exercised and issued (2023: 128,160 shares; GB£0.56 per share). Additionally, no shares (2023: 79,327 shares) were issued during the year to satisfy the Company's obligations with regards to the performance shares and 344,225 shares (2023: 101,063 shares) were issued to meet the obligations with regards to the restricted shares[9].

The share buyback programme was launched in 2022 with a maximum amount of US 25.0 million and will not exceed 46,574,528 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.

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[10] (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.

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.

30. DIVIDENDS

The Company did not declare any dividend during the year (2023: US Nil).

31. 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.

32. SHARE-BASED PAYMENTS RESERVE

Share-based payments reserve represents the cumulative value of share-based payment expenses recognised in relation to equity-settled option granted under the Group's share-based compensation schemes. The reserve is transferred to share capital or retained earnings, as applicable, upon the exercise, lapse, or cancellation of the related share-based instruments.

The total expense arising from share-based payments of US 0.4 million (2023: US 0.8 million) was recognised as 'administrative staff costs' (Note 7) in profit or loss for the year ended 31 December 2024.
During the year, US 0.3 million of restricted shares was vested and has been reclassified from share-based payments reserve to share capital as shown in Note 29.

The share-based payment expense arose from share options, performance shares and restricted shares[11] were awarded from 2020 to 2022. The performance share grants were suspended in 2023 by the Remuneration Committee in view of the performance of the Group 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 39). 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.

32.1 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[12]	63.0% to 66.7%
Share price	GB£ 1.01
Exercise price	GB£ 0.92
Expected dividends	1.96%

32.2 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[13]	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

32.3 Restricted shares[14]

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 2024:

			Share 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 2023	**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**
Vested during the year	-	(344,225)		0.76	7.19	2,118,585
Expired unexercised during the year	(967,794)	-	(125,418)	0.59	-	(125,418)
Granted during the year	-	1,242,000	-	-	-	-
As at 31 December 2024	**1,249,309**	**1,242,000**	**19,140,703**	**0.45**	**4.67**	**18,501,683**

The weighted average share price on the exercise date in 2023 was GB£0.83.

	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 2023	16,508,516	0.26 - 0.99	0.41	4.92
Share options exercisable as at 31 December 2024	18,501,683	0.26 - 0.99	0.45	4.67

33. 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 29).

34. HEDGING RESERVE

	2024 USD'000	2023 USD'000
At beginning of the year	14,131	-
Loss arising on changes in fair value of hedging instruments during		

the year	14,849	30,509
Income tax related to loss recognized in other comprehensive income	(4,455)	(9,153)
Net loss reclassified to profit or loss (Note 4)	(27,417)	(10,322)
Income tax related to amounts reclassified to profit or loss	8,225	3,097
At end of the year	**5,333**	**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 40 for further details on the hedging arrangements.

35. 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 2023	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
Change in estimation (Note 20)	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 27)	28,176	-	-	-	28,176
Reclassification	(127)	(2,000)	-	-	(2,127)
As at 31 December 2023 and 1 January 2024	**603,902**	**5,647**	**1,034**	**1,112**	**611,695**
Credited to profit or loss	-	-	-	(1,112) [(f)]	(1,112)[(f)]
Accretion expense (Note 14)	22,544	-	-	-	22,544
Change in estimation (Notes 13 and and 20)	(32,518)	-	-	-	(32,518)
Payment/Utilised	-	(5,000)	(12)	-	(5,012)
Fair value adjustment - Lemang PSC (Note 14)	-	53	-	-	53
Acquisition of additional interest of CWLH Assets (Note 18)	65,881	-	-	-	65,881
Additions during the year (Note 19)[(g)]	-	-	-	10,000[(g)]	10,000[(g)]
Reclassification	(1,038)[(d)]	-	-	-	(1,038)[(d)]
As at 31 December 2024	**658,771**	**700**	**1,022**	**10,000**	**670,493**
As at 31 December 2023					
Current	102,811[(e)]	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**
As at 31 December 2024					
Current	4,109[(e)]	700	733	-	5,542
Non-current	654,662	-	289	10,000	664,951
	658,771	**700**	**1,022**	**10,000**	**670,493**

(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 and PenMal Assets remains largely unchanged from 2023. There is an addition of US 62.6 million mainly due to the acquisition of additional interest of CWLH Assets as disclosed in Note 18. The blended inflation rates and risk-free rates used, plus the estimated decommissioning year of each asset are as follows:

		Blended inflation rate		Blended risk-free rate		Estimated decommissioning
No.	Asset	2024	2023	2024	2023	year
1.	Montara	2.40%	2.55%	4.32%	3.99%	2031
2.	Stag	2.30%	2.30%	4.60%	4.08%	2036
3.	Lemang PSC	2.45%	2.24%	6.45%	6.09%	2036
4.	PenMal Assets	2.15%	2.09%	3.67% - 3.89%	3.52% - 3.80%	2026 onwards
5.	CWLH Assets	2.41%	2.58%	4.51%	4.03%	2036

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 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 licenses 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 US 0.7 million as at 31 December 2024 (2023: US 5.6 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 and payment made after the first gas date of 31 July 2024.

No.	Trigger event	Consideration	Directors' rationale
1.	First gas date	US 5.0 million	The first gas date was on 31 July 2024 and this has been paid on 17 September 2024.
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 occurred on 31 July 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 above US 620/MT in 2024, which is the year of operation.
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

			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, which is the year of operation.

No.	Trigger event	Consideration	Directors' rationale
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.

(d) US 1.0 million reclassification related to the abandonment payment made from the CWLH Asset trust fund, following the operator's statement which was recorded under asset retirement obligations.

(e) US 102.8 million was reclassified from current asset restoration obligations to non-current asset restoration obligation due to the deferral of decommissioning activities for the Penmal Puteri Cluster SFA as disclosed in Note 24.

(f) US 1.1 million credited to profit or loss due to a change in underlying assumptions for provisions for manpower related at Montara.

(g) During the year, the group provided US 10.0 million toward an exploration commitment well for the Nam Du field development located in Block 46/07. The well has been incorporated into the field development plan ("FDP") for the gas facility, which management expects to receive approval from Vietnamese regulatory authorities in the second half of 2025. The commitment well obligation had previously received several extensions approvals from PetroVietnam, with the final extension expiring on 29 June 2024. According to the production sharing contract terms, should the FDP not receive approval from the relevant authorities, the group would be liable for a US 10.0 million penalty payable to PetroVietnam within 30 days of formal rejection notification. The Nam Du field is estimated to contain approximately 93.9 mmboe of 2C contingent resource.

36. BORROWINGS

	2024 USD'000	2023 Reclassified* USD'000
Non-current secured borrowings		
Reserve based lending facility	122,978	131,729
Current secured borrowings		
Reserve based lending facility	77,212	22,844
	200,190	**154,573**

On 19 May 2023, the Group signed a US 200.0 million RBL facility with a group of four international banks, with a fifth bank entering on 15 November 2023. The facility tenor is four years, with the final maturity date being the earlier of 31 March 2027 and the projected reserves tail[15] (which is expected later).

The borrowing base[16] was initially 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. At the March 2024 redetermination, Stag was removed from the borrowing base and replaced with a second tranche of CWLH acquisition which completed in February 2024 as disclosed in Note 18. Notwithstanding the removal of Stag from the borrowing base for the purpose of calculating the borrowing base amount, Jadestone Energy (Australia) Pty Ltd, as Stag titleholder, remains an Obligor under the RBL facility such that security in favour of the lenders over Stag titles, bank accounts and insurance remains in place and the information undertakings and restrictions on cash movement to entities outside RBL continue to apply.

The maximum facility limit is at US 200.0 million. The borrowing base was at US 200 million throughout the financial year 2024 (2023: US 200 million), and at the March 2025 redetermination, it was reduced to US 167.0 million.

Under the RBL facility the Group pays interest at 450 basis points over the secured overnight financing rate (SOFR), plus the applicable credit spread which is between 0.11% to 0.45% depending on the duration of the relevant interest period. The Group also pays customary arrangement and commitment fees.

As at 31 December 2024, the Group had incurred total interest expenses of US 21.5 million (2023: US 10.2 million) and US 0.1 million of commitment fees (2023: US 0.6 million), of which US 5.1 million (US 2.4 million) has been capitalised as disclosed in Note 20. The net interest expenses of US 16.4 million (2023: US 8.1 million) and US 0.1 million (2023: US 0.3 million) commitment fees are disclosed in Note 14.

* US 15.8 million of borrowings reported as at 31 December 2023 has been reclassified from non-current to current following changes in the basis of assumptions.

The Group entered into a committed standby working capital facility with Tyrus Capital S.à.r.l as part of the equity raise on 6

June 2023 for US 31.9 million. This facility matured on 31 December 2024. The facility carried interest of 15% on drawn amounts and 5% on undrawn amounts. For the year ended 31 December 2024, the Group incurred interest expense of US 1.5 million (2023: US 1.0 million) as disclosed in Note 14.

The secured borrowings is subject to a financial covenant which is tested semi-annually on 30 June and 31 December each year. The covenant measures the group's gearing ratio as calculated in note 42. The group has complied with this covenant in 2024 and 2023

37. LEASE LIABILITIES

	2024 USD'000	2023 USD'000
Presented as:		
Non-current	5,308	18,746
Current	12,243	14,118
	17,551	**32,864**
Maturity analysis of lease liabilities based on undiscounted gross cash flows:		
Year 1	15,083	17,357
Year 2	3,571	14,662
Year 3	-	3,674
Future interest charge	(1,103)	(2,829)
	17,551	**32,864**

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.

38. 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 2023	**-**	**9,107**
Repayment of lease liabilities	-	(17,171)
Repayment of borrowings	(75,000)	-
Total drawdown of borrowings	232,000	-
New lease liabilities	-	38,157
Borrowings costs paid	(7,595)	-
IInterest on borrowings paid	(5,007)	-
Commitment fees of borrowings paid	(658)	-
Interest expense	2,571	-
RBL commitment fees	349	-
Non-cash changes - interest	5,518	2,771
Capitalisation of borrowing costs (Note 20)	2,395	-
As at 31 December 2023 and 1 January 2024	**154,573**	**32,864**
Repayment of lease liabilities	-	(18,985)
Total drawdown of borrowings	43,000	-
New lease liabilities	-	1,207
Interest on borrowings paid	(18,944)	

Interest on borrowings paid	(18,944)	-
Commitment fees of borrowings paid	(142)	
RBL commitment fees	142	
Non-cash changes - interest	16,428	2,465
Capitalisation of borrowing costs (Note 20)	5,133	-
As at 31 December 2024	**200,190**	**17,551**

39. TRADE AND OTHER PAYABLES

	2024 USD'000	2023 USD'000
Current		
Trade payables	26,520	36,056
Other payables	12,809	13,105*
Accruals	51,805	56,534
Contingent payments	-	2,000
Malaysian supplementary payment payables	392	2,152
Amount due to joint arrangement partner	1,082	1,252
Overlift crude oil inventories	-	6,004
GST/VAT payables	185	881
	92,793	**117,984**
Non-current		
Other payable	16,917	16,917
Accrual	365	49
	17,282	**16,966**
	110,075	**134,950**

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 (2023: 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 initial acquisition of the CWLH Assets as the annual average Brent crude price in 2023 exceeded US 60/bbl. The payment was made in January 2024.

The overlift crude oil inventories in 2023 represent entitlement imbalances at year end of 195,698 bbls at the CWLH. The overlift liabilities are measured at cost of US 30.68/bbl. The CWLH Assets are in an underlift position as at 2024 year end as disclosed in Note 27.

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 it withdrew from the licenses in 2023 as disclosed in Note 27.

*US 4.5 million relating to outstanding swap contracts that matured in Quarter 4 in 2023 and were settled in January 2024 has been reclassified from derivative financial instruments to other payables as at 31 December 2023.

The non-current accrual represents the DCP plan granted during the year as disclosed in Note 32. The DCP has a vesting period of three years with pre-conditions for vesting to take place. The three years vesting period will also be the assessment period to assess if the pre-conditions are met. Upon vesting period of three years with pre-condition met, DCP will be settled by cash on different payout rates subject to the performance of the Group. The performance measures for DCP is similar to the performance shares as disclosed in Note 32.2. The DCP is measured at fair value as at 31 December 2024.

40. DERIVATIVE FINANCIAL INSTRUMENTS

	2024 USD'000	2023 USD'000 *Reclassified
Derivative financial liabilities		
Designated as cash flow hedges		
Commodity swap	7,618	20,607
Measured at fair value though profit or loss		
Foreign exchange forward contracts	-	73
	7,618	**20,680**
Analysed as:		
Current	7,618	13,972
Non-current	-	6,708

	7,618	20,680

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

Contract quantity	Type of contracts	Term	Contract price	Hedge classification	Fair value asset at 31 December 2024 USD'000	Fair value asset at 31 December 2023 USD'000
Contracts designated as cash flow hedges						
50% of Group's planned 2P production	Commodity swap: swap component(a)	Oct 2023 - Sep 2025	Weighted average price of US 70.57/bbl	Cash flow	(7,618)	(20,607)*

*US 4.5 million relating to outstanding swap contracts that matured in Quarter 4 in 2023 and were settled in January 2024 has been reclassified from derivative financial instruments to other payables as at 31 December 2023

Contract quantity	Type of contracts	Term	Contract price	Hedge classification	Fair value asset at 31 December 2024 USD'000	Fair value asset at 31 December 2023 USD'000
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)

(a) Swap component referring to hedge sales and the price of the commodity.

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 licenses. The forward contract was 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. No such contract entered in 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	-	20,680
2024				
Cash flow hedges				
Commodity swap component	1,733,020	119,698	-	7,618

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

	Amount reclassified to	Line item in

	Current period hedging loss 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	profit or loss due to hedged item affecting profit or loss USD'000	profit or loss in which reclassification adjustment is included
2023					
Cash flow hedges					
Forecast sales	(20,680)*	-	Other expenses	(10,322)	Revenue
2024					
Cash flow hedges					
Forecast sales	(7,618)	-	Other expenses	(27,417)	Revenue

*US 4.5 million relating to outstanding swap contracts that matured in Quarter 4 in 2023 and were settled in January 2024 has been reclassified from derivative financial instruments to other payables as at 31 December 2023.

41. 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.

Management applies the Black-Scholes option-pricing model to estimate the fair value of warrants. As at 31 December 2024, the fair value of warrant liability was US 0.9 million (2023: US 3.5 million). The movement in the fair value of warrants liability of US 2.5 million is disclosed in Note 15.

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

	2024	2023
Risk-free rate	4.48%	3.77%
Expected life	1.4 years	2.5 years
Expected volatility[17]	59.5%	54.5%
Share price	GB£ 0.24	GB£ 0.37
Exercise price	GB£ 0.50	GB£ 0.50
Expected dividends	0%	0%

42. 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.

	2024 USD'000	2023 USD'000
Financial assets		
At amortised cost		
Trade and other receivables, excluding prepayments, GST/VAT receivables and underlift crude oil inventories	287,027	241,179
Cash and bank balances	95,226	153,404
	382,253	**394,583**
Financial liabilities		
At amortised cost		
Trade and other payables, excluding contingent payments, GST/VAT payables and overlift crude oil inventories	109,890	126,065*
Lease liabilities	17,551	32,864
Borrowings	200,190	154,573
Contingent consideration for Lemang PSC acquisition	700	5,647
Contingent consideration for CWLH Assets acquisition	-	2,000
	328,331	**321,149**

*US 4.5 million relating to outstanding swap contracts that matured in Quarter 4 in 2023 and were settled in January 2024 has been reclassified from derivative financial instruments to other payables as at 31 December 2023.

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 40).

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 2024 USD'000	Effect on other comprehensive income before tax for the year ended 31 December 2024 USD'000	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
Increase by 10%	-	(12,732)	-	(33,861)
Decrease by 10%	-	12,732	-	33,861

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.

Foreign currency sensitivity

Material foreign denominated balances were as follows:

	2024 USD'000	2023 USD'000
Cash and bank balances		
Australian Dollars	1,894	4,777
Malaysian Ringgit	4,820	8,533
Trade and other receivables		
Australian Dollars	21,826	250
Malaysian Ringgit	9,837	42,672
Trade and other payables		
Australian Dollars	41,676	33,250
Malaysian Ringgit	42,027	59,113

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 4.1 million (2023: US 3.5 million), and which would be charged/credited to the consolidated statement of profit or loss.

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 2024, the Group held US 165.8 million (2023: US 82.0 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 3.16% (2023: 4.5%).

As at 31 December 2024, the Group held US Nil million (2023: US 55.0 million) in fixed term deposits. The fixed term deposits generate average annual interest rate of 4.5% (2023: 4.5%).

On 19 May 2023, the Group signed a US 200.0 million RBL facility with a group of four international banks, with a fifth bank entering on 15 November 2023 ("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[18] (which is expected later). The borrowing base[19] 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 maximum facility limit is at US 200.0 million. The borrowing base was at US 200 million throughout the financial year 2024 (2023: US 200 million), and at the March 2025 redetermination, it was reduced to US 167.0 million.

As at 31 December 2024 the Group has a net drawdown sum of US 200.0 million (2023: US 157.0 million). The loan incurred costs of US 7.0 million in 2023. The RBL facility pays interest at 450 basis points over the secured overnight financing rate, plus the applicable credit spread which is between 0.11% to 0.45% depending on the duration of the relevant interest period. The Group also pays customary arrangement and commitment fees.

Based on the carrying value of the CWLH Assets abandonment trust fund, fixed term deposits and RBL as at 31 December 2024, 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 (2023: profit before tax increased/decreased by US 0.1 million).

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 for oil sales, Malaysia for both oil and gas sales and Indonesia for gas sales. In addition to there are several customers for LPG and condensate sales in Indonesia 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[20]
Doubtful	Amount is > 30 days past due indicating significant increase in credit risk since initial recognition	Lifetime ECL - not credit-impaired
In default	Amount is >90 days past due is evidence indicating the assets 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) USD'000	Loss allowance USD'000	Net carrying amount USD'000
2024							
Cash and bank balances	28	n.a	Performing	12m ECL	95,226	-*	95,226
Trade receivables	27	A2	(i)	Lifetime ECL	15,846	-*	15,846
Other receivables	27	n.a	(i)	12m ECL	7,731	-*	7,731
Amount due from joint arrangement partners (net)	27	n.a	(i)	12m ECL	2,390	-*	2,390
Non-current other receivables	27	n.a	(i)	12m ECL	261,517	-*	261,517
2023							
Cash and bank balances	28	n.a	Performing	12m ECL	153,404	-*	153,404
Trade receivables	27	A2	(i)	Lifetime ECL	12,533	-*	12,533
Other receivables	27	n.a	(i)	12m ECL	88,005	-*	88,005
Amount due from joint arrangement partners (net)	27	n.a	(i)	12m ECL	12,911	-*	12,911
Non-current other							

receivables	27	n.a	(i)	12m ECL	127,730	-*	127,730

* 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. As at year end, ECL from trade receivables are expected to be insignificant.

As at 31 December 2024, total trade receivables amounted to US 15.8 million (2023: US 12.5 million). The balance in 2024 and 2023 had been fully recovered in 2025 and 2024, respectively, except for US 0.5 million (2023: US Nil) allowance for expected credit loss has been recognised due to bad debts.

The concentration of credit risk relates to the Group's single customer with respect to oil sales in Australia, a different single customer for oil and gas sales in Malaysia and a different single customer for gas in Indonesia. All 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 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.

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 44.1 million (2023: US 91.3 million). Operating cash flows before movements in working capital and net cash used in operating activities for the year ended 31 December 2024 was US 70.5 million and US 30.7 million (2023: US 36.5 million and US 12.1 million) respectively. The Group's net current asset remained positive at US 9.2 million as at 31 December 2024 (2023: US 22.3 million).

On 19 May 2023, the Group signed a US 200.0 million RBL facility with a group of four international banks, with a fifth bank entering on 15 November 2023 ("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 maximum facility limit is at US 200.0 million. The maximum facility limit is at US 200.0 million. The borrowing base was at US 200 million throughout the financial year 2024 (2023: US 200 million), and at the March 2025 redetermination, it was reduced to US 167.0 million.

The Group is required to maintain a parent company financial covenant as disclosed in Note 36 of consolidated net debt below 3.5x annual EBITDAX and to deliver the required information to the RBL Banks on a timely basis. As at 31 December 2024, the Company's financial covenant was 1.20 (2023: 0.14).

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

<u>Derivative and non-derivative financial liabilities</u>
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**	**Within 2 to years USD'000**
2024			
Non-interest bearing			
Trade and other payables, excluding contingent payments, GST/VAT payables and overlift crude oil inventories	-	92,608	17,28
Contingent consideration for Lemang PSC acquisition	-	700	
Derivative financial instruments designated as cash flow hedges	-	7,618	
Fixed interest rate instrument			
Lease liabilities	9.778	15,083	3,57
Variable interest rate instrument			
Borrowings	12.789	77,212	122,97
		193,221	**143,83**
2023			
Non-interest bearing			
Trade and other payables, excluding contingent payments, GST/VAT payables			

and overlift crude oil inventories*	-	109,099	16,96
Contingent consideration for Lemang PSC acquisition	-	5,000	64
Contingent consideration for CWLH Assets acquisition	-	2,000	
Derivative financial instruments designated as cash flow hedges*	-	13,972	6,70
Derivative financial instrument carried at FVTPL	-	73	
Fixed interest rate instrument			
Lease liabilities	9.660	14,118	18,74
Variable interest rate instrument			
Borrowings*	11.084	22,844	131,72
		167,106	**174,79**

* US 15.8 million of borrowings reported as at 31 December 2023 has been reclassified from non-current to current as disclosed in Note 36. US 4.5 million of derivative financial liabilities instruments as at 31 December 2023 has been reclassified to trade and other payables as disclosed in Note 39 and Note 40.

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 USD'000	Within 2 to 5 years USD'000	More than 5 years USD'000	Total USD'000
2024					
Non-interest bearing					
Trade and other receivables, excluding prepayments, GST/VAT receivables and underlift crude oil inventories[a]	-	25,510	261,517	-	287,027
Variable interest rate instruments					
Cash and bank balances	-[b]	94,338	888	-	95,226
		119,848	**262,405**	**-**	**382,253**
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	-[b]	152,396	1,008	-	153,404
		265,845	**128,738**	**-**	**394,583**

[a] There are US 6.3 million (2023: US 2.9 million) of abandonment trust funds that are interest bearing with a weighted average effective interest rate of 3.16% (2023: 4.5%)

[b] The effect of interest is not material.

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 29, 31, 32, 33 and 34, 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 regularly review the Group's capital management strategy and consider the current approach appropriate, given the Group's relative size. The decline in the Net Debt to Equity ratio during the year primarily reflects increased borrowings to fund the Akatara gas facility and the second tranche acquisition of CWLH, as well as a reduction in equity due to higher upfront borrowing costs reserve.These impacts were incurred without the benefit of a full year of incremental production contributions from these investments. Looking ahead, these investments, together with the sale of Sinphuhorm, are expected to strengthen equity and reduce borrowings over time.

	2024 USD'000	2023 USD'000

Gearing ratio

Borrowings	200,190[21]	154,573[1]
Cash and cash equivalents	(95,226)	(153,404)
Net debt/(cash)	**104,964**	**1,169**
Equity	18,834	53,770
Net debt to equity ratio	**5.57**	**0.02**

The Group's overall strategy towards the capital structure remains unchanged as management anticipate the new investment will support debt reduction and improved equity in the future.

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 2024 Assets	2024 Liabilities	2023 Assets	2023 Liabilities	Fair value hierarchy	Valuation technique(s) and key input(s)	Significant unobservable input(s)
Derivative financial instruments							
1) Commodity swap contracts (Note 40)	-	7,168	-	20,607*	Level 2	Third party valuations based on market comparable information.	-
2) Foreign forward contracts (Note 40)	-	-	-	73	Level 2	Third party valuations based on market comparable information.	-
Others - contingent consideration from Lemang PSC acquisition							
3) Contingent consideration (Note 35)	-	700	-	5,647	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, forecasted Dated Brent oil prices of US 73.00/bbl in 2025 and Saudi CP prices of US 587.95/MT in 2025, estimated future recoverability of VAT receivables as well as the effect of the time value of money.	-

*US 4.5 million relating to outstanding swap contracts that matured in Quarter 4 in 2023 and were settled in January 2024 has been reclassified fr instruments to other payables as at 31 December 2023.

Financial assets/financial liabilities	Fair value (USD'000) as at 2024 Assets	2024 Liabilities	2023 Assets	2023 Liabilities	Fair value hierarchy	Valuation technique(s) and key input(s)	Significant unobservable input(s)
Others - contingent consideration from CWLH Assets acquisition							
4) Contingent consideration (Notes 35 and 39)	-	-	-	2,000	Level 1	Based on the actual average Dated Brent prices in 2023 of US 82.64/bbl.	-

1. 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 Australia, Malaysia, Indonesia, and Thailand.

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

	Producing assets				Exploration/development		
	Australia USD'000	Malaysia USD'000	Indonesia USD'000	Thailand USD'000	Vietnam USD'000	Indonesia USD'000	Corpora USD'0
2024							
Revenue							
Liquids revenue	301,886	76,661	4,214	-	-	-	
Gas revenue	-	1,600	10,675	-	-	-	
	301,886	**78,261**	**14,889**	**-**	**-**	**-**	
Production cost	(221,844)	(43,277)	(11,848)	-	-	-	
Depletion, depreciation and amortisation	(77,297)	(10,956)	(2,809)	-	(89)	-	(2
Administrative staff costs	(15,082)	(5,427)	(393)	-	(1,162)	(535)	(11,8
Other expenses	(8,949)	(4,693)	(3,220)	(1,623)	(463)	(624)	(4,7
Share of results of associate	-	-	-	1,553	-	-	
Other income	25,370	3,618	44	7	-	-	
Finance costs	(24,444)	(4,108)	(734)	(1)	(6)	-	(15,8
Other financial gains	-	73	-	-	-	-	2,
(Loss)/Profit before tax	**(20,360)**	**13,491**	**(4,071)**	**(64)**	**(1,720)**	**(1,159)**	**(29,5**
Additions to non-current assets	103,022	43,000	535	-	11,837	42,309	
Non-current assets[a]	262,784	289,530	178,501	19,544	84,056	-	

[a] The non-current assets in the segmental note exclude deferred tax assets from the consolidated statement of financial position.

	Producing assets				Exploration/developmer	
	Australia USD'000	Malaysia[b] USD'000	Indonesia[b] USD'000	Thailand[b] USD'000	Vietnam[b] USD'000	Indonesia USD'00
2023						
Revenue						
Liquids revenue	240,630	66,517	-	-	-	
Gas revenue	-	2,053	-	-	-	
	240,630	**68,570**	**-**	**-**	**-**	
Production cost	(185,039)	(47,733)	-	-	-	
Depletion, depreciation and amortisation	(65,204)	(10,397)	-	-	(90)	(1
Administrative staff costs	(14,550)	(5,060)	-	-	(1,773)	
Other expenses	(12,652)	(3,182)	-	(181)	(395)	(1,9
Impairment of assets	(17,410)	(12,271)	-	-	-	
Share of results of associate	-	-	-	2,640	-	
Other income	9,990	192	-	-	25	7,
Finance costs	(22,611)	(6,565)	-	-	-	(2,2
(Loss)/Profit before tax	**(66,846)**	**(16,446)**	**-**	**2,459**	**(2,233)**	**3,**
Additions to non-current assets	86,403	54,576	-	-	90,611	
Non-current assets[a]	346,281	164,899	-	26,651	72,556	136,

[a] The non-current assets in the segmental note exclude deferred tax assets from the consolidated statement of financial position.

[b] The SEA category from the prior year has been split into Malaysia, Indonesia, and Thailand, while the Exploration/Development category has been separated into Vietnam and Indonesia. Accordingly, the prior year figures have been reclassified to reflect these change.

Revenue arising from producing assets relates to the Group's single customer with respect to oil sales in

Australia, different single customers for oil and gas sales in Malaysia, different single customer for gas sales in Indonesia and several customers for LPG and condensate sales in Indonesia. There is an active market for the Group's oil and gas so they can be sold to other buyers, if required.

43. 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

	2024 USD'000	2023 USD'000
Not later than one year	460	10,400
One to five years	9,404	9,284
More than 5 years	1,978	2,619
	11,842	**22,303**

The SEA portfolio PSC operational commitment as at 31 December 2024 amounted to US 7.3 million (2023: US 17.3 million) relates to Lemang PSC. In 2023, US 10.0 million relates to the minimum work commitment outstanding for the Block 46/07 PSC which provision has been provided this year as disclosed in Note 35. The operational commitments also include training commitment of US 4.7 million (2023: US 5.0 million), for the Block 46/07 PSC, Block 51 PSC and the PenMal Assets.

<u>Work commitment</u>

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 (2023: 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 license. 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 (2023: US 0.3 million), US 0.1 million (2023:US Nil) and US Nil (2023: US 0.1 million) for PM323 PSC, PM428 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 expenditures that were contracted for at the end of the reporting year but not recognised as liabilities:

	2024 USD'000	2023 USD'000
Not later than one year	13,611	28,489
One to five years	2,652	2,570
	16,263	**31,059**

The capital commitments of US 11.8 million as at 2024 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 has been completed during the year and the group successfully commenced operations on 31 July 2024.

The Group also contracted for US 4.2 million for capital expenditure replacement in Montara and US 0.2 million which is associated with Stag capital expenditure.

44. 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 2025. It is too early to reliably estimate the outcome of the investigation and if any prosecution will eventuate.

Akatara Gas development Change Orders

As part of the final project reconciliation for Akatara, the Group is in discussions with the Contractor (JGC) concerning change orders raised over the course of the project. Any final agreement would depend on the assessment of all contractual obligations, documentation of approved modifications, and resolution of any outstanding claims from both parties.

45. EVENTS AFTER THE END OF THE REPORTING PERIOD

Redetermination of the borrowing base under the reserves-based lending facility

On 2 April 2025, the RBL Banks finalised a routine redetermination of the borrowing base under RBL, with the revised borrowing capacity reduced from US 200.0 million to US 167.0 million following the sale of Sinphuhorm and the passing of the Lemang completion test. The reduction in the RBL was made on 17 April 2025 from the cash receipt generated from the sale of Sinphuhorm.

Working Capital facility for US 30.0 million with international bank.

On 10 April 2025, the Group closed a US 30.0 million working capital facility with international bank with a maturity date of 31 December 2026. The facility carries a Secured Overnight Financing Rate ("SOFR"), plus 7% margin and was undrawn at the date of signing the financial statements. The facility, if, required, may be drawn upon to support general corporate purposes.

Sale of Sinphuhorm for US39.4 million

On 16 April 2024, the Grouphas divested its 9.52% interest in the producing Sinphuhorm gas field and Dong Mun discovery onshore Thailand to PTTEP HK Holding Limited, a subsidiary of PTTEP, Thailand's national oil and gas company, for a cash consideration of US 39.4 million, with a further US 3.5 million in cash payable contingent on future license extensions.

The US 39.4 million received consists of a US 35.0 million base consideration as of the effective date of 1 January 2025, plus adjustments between the effective date and closing date of 16 April 2025. A further US 3.5 million in cash is payable in the event of an extension to either of the two petroleum licenses which contain the Sinphuhorm field, which currently expire in 2029 and 2031, respectively.

Change in Board of Directors

On 16 January 2025, the company announced the appointment of David Mendelson as an independent non-executive director. Mr. Mendelson is a member of the Board's Remuneration Committee and Governance and Nomination Committee. On the same day,the Company announced the resignation of Cedric Fontenit as an independent non-executive director.

46. 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, the Group's largest shareholder, 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 at that time were 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 in 2023, the Company 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 in 2023, 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,the Group's largest shareholder, 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 matured 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 and remained undrawn as at 31 December 2024.

Compensation of key management personnel

	2024 USD'000	2023 USD'000
Short-term benefits	2,526	2,598
Other benefits	181	-
Share-based payments	233	300
Compensation for loss of office	2,464	
	5,404	**2,898***

The total remuneration of key management members (including salaries and benefits) was US 5.4 million (2023: US 2.9 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
2024				
A. Paul Blakeley	908	2,543	90	3,541
Bert-Jaap Dijkstra	757	92	132	981
Dennis McShane	39	-	-	39
Iain McLaren	48	-	-	48
Robert Lambert	24	-	-	24
Cedric Fontenit	89	-	-	89
Lisa Stewart	25	-	-	25
David Neuhauser	80	-	-	80
Jenifer Thien	100	-	-	100
Joanne Williams	89	-	8	97
Adel Chaouch	157	-	-	157
Andrew Fairclough	141	10	3	154
Linda Beal	69			69
Gunter Waldner[(b)]	-	-	-	-
	2,526	**2,645**	**233**	**5,404**

*The change in prior year figures is due to a revised disclosure basis applied in 2024, whereby only non-executive and executive directors are identified as key management personnel in accordance with IAS 24 Related Party Disclosures, with senior management no longer included.

	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**

[(a)] Short-term benefits comprise salary, director fee as applicable, performance pay, pension and other allowances. Other benefits comprise benefits-in-kind. Other benefits include compensation for loss of office amounting to US 2.3 million, including US 0.2 million of payroll tax for A. Paul Blakeley.

[(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.

performing the Non-Executive Director duties.

(c) During the year, A.Paul Blakeley, Bert-Jaap Dijkstra, Dennis McShane, Ian Mclaren, Robert Lambert and Lisa Stewart stepped down as the directors. Joanne Williams, Adel Chaouch, Andrew Fairclough and Linda Beal were appointed during the year.

Company Statement of Financial Position as at 31 December 2024

	Notes	2024 USD'000	2023 USD'000
Assets			
Non-current assets			
Investment in subsidiaries	5	28,005	27,598
Loan to a subsidiary	7	214,579	217,112
Total non-current asset		**242,584**	**244,710**
Current assets			
Amount owing by subsidiaries		128,776	105,875
Prepayments		30	1,910
Cash and cash equivalents		979	56,588
Total current assets		**129,785**	**164,373**
Total assets		**372,369**	**409,083**
Equity and liabilities			
Equity			
Capital and reserves			
Share capital	8	457	456
Share premium account	8	52,176	51,827
Merger reserve	10	61,068	61,068
Share-based payment reserve	11	27,730	27,673
Capital redemption reserve		24	24
Retained earnings		228,575	235,842
Total equity		**370,030**	**376,890**

	Notes	2024 USD'000	2023 USD'000
Liabilities			
Current liabilities			
Other payables and accruals	12	1,408	1,455
Amount owing to a subsidiary		-	27,269
Warrant liability	13	931	3,469
Total current liabilities		**2,339**	**32,193**
Total liabilities		**2,339**	**32,193**
Total equity and liabilities		**372,369**	**409,083**

During the year, the Company made a loss after tax of US 7.3 million (2023: US 4.9 million profit after tax).

Company Statement of Changes in Equity for the year ended 31 December 2024

	Share capital USD'000	Share premium account USD'000	Capital redemption reserve USD'000	Share-based payments reserve USD'000	Merg reser USD'0
As at 1 January 2023	339	983	21	26,907	61,0
Share-based compensation:					
Company	-	-	-	6	
Subsidiaries	-	-	-	760	
Shares issued (Note 8)	120	52,846	-	-	
Transaction costs associated with issuance of shares (Note 29)	-	(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 and 1 January 2024	**456**	**51,827**	**24**	**27,673**	**61,0**
Share-based compensation:					
Company	-	-	-	-	
Subsidiaries	-	-	-	407	
Shares issued (Note 8)	1	349	-	(350)	
Total transactions with owners	**457**	**52,176**	**24**	**27,730**	**61,0**
Loss and total comprehensive income for the year	-	-	-	-	
As at 31 December 2024	**457**	**52,176**	**24**	**27,730**	**61,0**

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 is 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/loss 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. MATERIAL ACCOUNTING POLICY INFORMATION

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 subsidiary

Investment in subsidiary is 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 SUBSIDIARY

	2024 USD'000	**2023 USD'000**
Unquoted share, at cost	-*	-*
Share-based payment:		
At beginning of year	27,598	26,838
Share-based compensation at subsidiaries during the year	407	760
At end of year	**28,005**	**27,598**
	28,005	**27,598**

* 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 2024**	**% voting rights and ordinary shares held 2023**	**Nature of business**

Name of the company	Place of incorporation	% voting rights and ordinary shares held 2024	% voting rights and ordinary shares held 2023	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 (Lemang) Pte Ltd (4)	Singapore	100	100	Exploration
Jadestone Energy Ltd (5)	Bermuda	100	100	Investment holdings
Jadestone Energy (Malaysia) Pte Ltd (4)	Singapore	100	100	Production of oil & gas
Jadestone Energy (PHT GP) Limited (1)	England and Wales	100	100	Investment holdings
Jadestone Energy (PM) Inc. (6)	Bahamas	100	100	Production of oil & gas
Jadestone Energy Pte Ltd (4)	Singapore	100	100	Investment holdings
Jadestone Energy (Singapore) Pte Ltd (4)	Singapore	100	100	Investment holdings
Jadestone Energy Sdn Bhd (7)	Malaysia	100	100	Administration
Jadestone Energy (Thailand) Pte Ltd (4)	Singapore	100	100	Investment holdings
Jadestone Energy UK Services Ltd (1)	England and Wales	100	100	Administration
Mitra Energy (Philippines SC- 56) Ltd (5)(a)	Bermuda	100	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 (8)	Delaware	100	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
(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) H&J Corporate Services Ltd, Ocean Centre, Montagu Foreshore, East bay Street, P.O. Box N-3247, Nassau, Bahamas
(7) Level 15-2, Bangunan Imperial Court, Jalan Sultan Ismail, 50250, Kuala Lumpur, Malaysia
(8) CT Corporation, 1209 Orange St, Wilmington, DE 19801, United States

(a) Mitra Energy (Philippines SC-56) Ltd was dissolved on 31 December 2024.

6. STAFF NUMBER AND COSTS

The Company had no employee in 2024. In 2023, the Company had one employee at the beginning of 2023, then the employee was transferred to a subsidiary during the year of 2023.

The aggregate remuneration comprised:

	2024 USD'000	2023 USD'000
Wages and salaries	-	9
Non-executive director's fee	701	764
	701	**773***

* In 2024, the amount of non-executive directors' fees has been disclosed under staff costs by management. Accordingly, US 0.8 million relating to 2023 has also been disclosed for comparative purposes.

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 amounts 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:

	2024 USD'000	2023 USD'000
Loan to a subsidiary		
At the beginning of the year	217,112	252,485
Repayment during the year	-	(52,865)
Unrealised foreign exchange differences	(2,533)	17,492
Total transaction during the year	**214,579**	**217,112**
Subsidiaries		
Advances	12,056	41,608
Repayment received	-	(33,583)
Payment on behalf by	39,289	65,328
Repayment made	(1,175)	7,525
Total transaction during the year	**50,170**	**80,878**

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, the Company's largest shareholder, 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 at that time were 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 in 2023, the Company 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 in 2023, 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 as disclosed in Note 41 to the consolidated financial statements.

Committed standby working capital facility

On 6 June 2023, the Company entered into a committed standby working capital facility with Tyrus,the Company's largest shareholder, 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 matured 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 and remained undrawn as at 31 December 2024.

For the year ended 31 December 2024, the Company had incurred interest expense of US 2.4 million (2023: 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

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 2023, at £0.001 each	**448,363,663**	**339**	**983**
Issued during the year	94,463,933	120	50,844
Share repurchases	(2,051,022)	(3)	-
As at 31 December 2023	**540,766,574**	**456**	**51,827**
Issued during the year	344,225	1	349
As at 31 December 2024	**541,110,799**	**457**	**52,176**

On 19 January 2023, the Companysuspended its share buyback programme. As at 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.

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[22] (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.

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.

During the year, no employee share options were exercised and issued (2023: 128,160 shares; GB£0.56 per share). Additionally, no shares (2023: 79,327 shares) were issued during the year to satisfy the Company's obligations with regards to the performance shares and 344,225 shares (2023: 101,063 shares) were issued to meet the obligations with regards to the restricted shares.

9. DIVIDENDS

The Company did not declare any dividend during the year.

10. 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.

11. SHARE-BASED PAYMENTS RESERVE

Share-based payments reserve represents the cumulative value of share-based payment expenses recognised in relation to equity-settled option granted under the Group's share-based compensation schemes. The reserve is transferred to share capital or retained earnings, as applicable, upon the exercise, lapse, or cancellation of the related share-based instruments.

The total expense arising from share-based payments of US 0.4 million (2023: US 0.8 million) was recognised as 'administrative staff costs' (Note 7) in profit or loss for the year ended 31 December 2024.
During the year, US 0.3 million of restricted shares was vested and has been reclassified from share-based payments reserve to share capital as shown in Note 29 to the consolidated financial statements.

The share-based payment expense arose from share options, performance shares and restricted shares[23] awarded from 2020 to 2022. The performance share grants were suspended in 2023 by the Remuneration Committee in view of the performance of the Group 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 39). 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[24]	63.0% to 66.7%
Share price	GB£ 1.01
Exercise price	GB£ 0.92
Expected dividends	1.96%

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[25]	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

10.3 Restricted shares[26]

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 2024:

	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 2023	**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**
Vested during the year	-	(344,225)		0.76	7.19	2,118,585
Expired unexercised during the year	(967,794)	-	(125,418)	0.59	-	(125,418)
Granted during the year	-	1,242,000	-	-	-	-

As at 31 December 2024	**1,249,309**	**1,242,000**	**19,140,703**	**0.45**	**4.67**	**18,501,683**

The weighted average share price on the exercise date in 2023 is GB£0.83.

	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 2023	16,508,516	0.26 - 0.99	0.41	4.92
Share options exercisable as at 31 December 2024	18,501,683	0.26- 0.99	0.45	4.67

12. OTHER PAYABLES

	2024 USD'000	2023 USD'000
Other payables	938	563
Accruals	470	892
	1,408	**1,455**

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.

13. 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.

Management applies the Black-Scholes option-pricing model to estimate the fair value of warrants. As at 31 December 2024, the fair value of warrant liability was US 0.9 million (2023: US 3.5 million). The differences of the fair value of warrants liability of US 2.5 million as disclosed in Note 15 to the consolidated financial statements.

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

	2024	2023
Risk-free rate	4.48%	3.77%
Expected life	1.4 years	2.5 years
Expected volatility[27]	59.5%	54.5%
Share price	GB£ 0.24	GB£ 0.37
Exercise price	GB£ 0.50	GB£ 0.50
Expected dividends	0%	0%

14. EVENTS AFTER THE END OF REPORTING PERIOD

Redetermination of the borrowing base under the reserves-based lending facility

On 2 April 2025, the RBL Banks finalised a routine redetermination of the borrowing base under RBL, with the revised borrowing capacity reduced from US 200.0 million to US 167.0 million following the sale of Sinphuhorm and the passing of the Lemang completion test. The reduction in the RBL was made on 17 April 2025 from the cash receipt generated from the sale of Sinphuhorm.

Working Capital facility for US 30.0 million with international bank.

On 10 April 2025, the Group closed a US 30.0 million working capital facility with international bank with a maturity date of 31 December 2026. The facility carries a Secured Overnight Financing Rate ("SOFR"), plus 7% margin and was undrawn at the date of signing the financial statements. The facility, if, required, may be drawn upon to support general corporate purposes.

Sale of Sinphuhorm for US39.4 million

On 16 April 2024, the Group has divested its 9.52% interest in the producing Sinphuhorm gas field and Dong Mun discovery onshore Thailand to PTTEP HK Holding Limited, a subsidiary of PTTEP, Thailand's national oil and gas company, for a cash consideration of US 39.4 million, with a further US 3.5 million in cash payable contingent on future license extensions.

The US 39.4 million received consists of a US 35.0 million base consideration as of the effective date of 1 January 2025, plus adjustments between the effective date and closing date of 16 April 2025. A further US 3.5 million in cash is payable in the event of an extension to either of the two petroleum licenses which contain the Sinphuhorm field, which currently expire in 2029 and 2031, respectively.

Change in Board of Directors

On 16 January 2025, the company announced the appointment of David Mendelson as an independent non-executive director. Mr. Mendelson is a member of the Board's Remuneration Committee and Governance and Nomination Committee. On the same day, the Company announced the resignation of Cedric Fontenit as an independent non-executive director.

GLOSSARY

1P reserves	those reserves with 90% probability of quantities actually recovered being equal or greater to the sum of estimated proved reserves
2P reserves	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
2C resources	best estimate contingent resource
AGPF	Akatara Gas Processing Facility
AIM	Alternative Investment Market
ARO	asset retirement obligations
bbl	barrel
bbls/d	barrels per day
bcf	billion standard cubic feet
the Board	the board of directors of Jadestone Energy plc.
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
CALM	catenary anchor leg mooring
CEO	chief executive officer
CFO	chief financial officer
CO_2-e	carbon dioxide equivalent
the Company	Jadestone Energy plc
CWLH	Cossack, Wanaea, Lambert and Hermes oil fields offshore Australia
DD&A	depletion, depreciation and amortization
EBITDAX	earnings before interest tax, depreciation, amortization and exploration
EPCI	engineering, procurement, construction and installation
ESG	Environment, Social and Governance
FOB	free on board, a commercial structure for selling oil, where the buyer takes responsibility for the cargo and transportation costs after loading onto an offtake tanker
FPSO	floating production storage and offloading
GHG	greenhouse gases
the Group	Jadestone Energy plc and its subsidiaries
GSPA	gas sales and purchase agreement
IEA	the International Energy Agency
IFRS	International Financial Reporting Standards
LPG	liquefied petroleum gas
LTI	lost-time injury
mcf	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
mmcf	million standard cubic feet
NDUM	Nam Du and U Minh gas fields offshore Vietnam
opex	operating expenditures
PenMal Assets	collectively, Jadestone's Peninsular Malaysia assets
PETRONAS	Petroliam Nasional Berhad
PITA	Malaysia Petroleum Income Tax
PNLP Assets	collectively, a number of oil fields offshore Peninsular Malaysia in which Jadestone acquired a non-operated interest as part of its wider Peninsular Malaysia entry in 2021. These assets, originally known as the PM318/AAKBNLP PSCs, were renamed the PNLP Assets after Jadestone assumed operatorship of the licenses in April 2023 following the withdrawal of the previous operator. Certain of the PNLP Assets were included in the Malaysia Bid Round Plus, with Jadestone subsequently being awarded a 100% interest in the Puteri Cluster in 2024.
PRRT	Petroleum Resource Rent Tax
PSC	production sharing contract
QCA Code	Quoted Companies Alliance Corporate Governance Code, a set of principles designed to promote good corporate governance practices among small and mid-sized companies, particularly those listed on the AIM market in the UK
R&M	repairs and maintenance
RBL Facility	the Group's US 200 million reserves-based lending facility closed in May 2023 with a four-year tenor
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
ROV	remote operated vehicle
US	United States dollar

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.

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.

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[1] Based on a Brent oil price range of US 70-80/bbl (real terms from 2025). Assumes midpoint of internal production expectations and that all barrels produced during 2025-27 are sold in the period. Does not reflect any capital expenditure or abandonment spend outside the Group's producing assets. Reflects upfront consideration from the sale of the Group's assets in Thailand on 16 April 2025.

[2] 2023 Scope 1 emissions have been restated due to a flare meter configuration issue at Stag which resulted in historical flaring volumes and GHG emissions to be underreported.

[3] Effective capacity may be less depending on operational factors and conditions.

[4] The local government has an option to take a 10% participating interest in the Lemang PSC, which, if exercised, would reduce Jadestone's working interest to 90%.

[5] The borrowing base represents the maximum loan amount that can be drawn under the RBL at any given time, subject to a redetermination every six months through the life of the loan.

[6] The closing adjustment represents the economic benefits of production since the effective date and completion.

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

[8] The offset of the deferred tax liabilities and deferred tax assets are withing respective tax jurisdiction.

[9] Restricted shares are granted to eligible employees and directors, subject to vesting conditions. Upon vesting, the shares are transferred directly to recipients and recognised in share capital.

[10] 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.

[11] Restricted shares are granted to eligible employees and directors, subject to vesting conditions. Upon vesting, the shares are transferred directly to recipients and recognised in share capital.

[12] 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] 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.

[14] Restricted shares are granted to eligible employees and directors, subject to vesting conditions. Upon vesting, the shares are transferred directly to recipients and recognised in share capital.

[15] 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.

[16] The borrowing base represents the maximum loan amount that can be drawn under the RBL at any given time, subject to a redetermination every six months through the life of the loan.

[17] 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.

[18] 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.

[19] The borrowing base represents the maximum loan amount that can be drawn under the RBL at any given time, subject to a redetermination every six months through the life of the loan.

[20] These does not apply to trade receivables as the Group has applied the simplified approach in IFRS 9 to measure the loss allowance at lifetime ECL.

[21] The borrowings of US 200.2 million (2023: US 154.6 million) represents the fair value of the balance. The gross outstanding balance as at 31 December 2024 is US 200.0 million (2023: US 157.0 million).

[22] 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.

[23] Restricted shares are granted to eligible employees and directors, subject to vesting conditions. Upon vesting, the shares are transferred directly to recipients and recognised in share capital.

[24] 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.

[25] 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.

[26] Restricted shares are granted to eligible employees and directors, subject to vesting conditions. Upon vesting, the shares are transferred directly to recipients and recognised in share capital.

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[27] 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.

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