2024 Half Year Results

17 September 2024—Singapore: Jadestone Energy plc (AIM:JSE) ("Jadestone" or the "Company"), an independent oil and gas production company and its subsidiaries (the "Group"), focused on the Asia-Pacific region, reports its unaudited condensed consolidated interim financial statements, as at and for the six-month period ended 30 June 2024 (the "financial statements").

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

Key updates:

- Akatara development project achieved mechanical completion in June 2024, with sales gas production commencing in July 2024 and reaching c.14mmscf/d. Production has been recently curtailed by a small mechanical issue in the gas processing facility's refrigeration compressors, with repairs underway. These repairs and their associated cost remain the responsibility of the EPCI contractor.
- Positive progress on the Montara oil storage tank repair and maintenance programme, which has allowed for the permanent stationing of shuttle tanker at the field to be discontinued in late-August, earlier than expected.
- Year-to date 2024 production (to end August 2024) has averaged c.17,500 boe/d, a c.42% increase year-on-year due to the success of both organic and acquisition driven growth over the period. Annual 2024 production guidance is reiterated at 18,500 – 21,000 boe/d, with an expected outcome towards the lower end of the range, given year-to-date production and ongoing Akatara activities.
- Operating expenditure guidance for 2024 is reiterated at US$240-280 million (excluding forecast royalties and carbon taxes of c.US$30 million),
- Capital expenditure and other cash expenditure guidance is unchanged at US$80-110 million and US$62 million respectively,
- US$31.1 million loss after tax for the first half of 2024, which includes a US$45.8 million non-cash charge to production costs related to the CWLH 2 acquisition, which closed in February 2024.
- Net debt of US$69.1 million at 30 June 2024 reflects c.US$130.9 million of consolidated Group cash balances and US$200.0 million of debt drawn under the Group's reserves-based lending ("RBL") facility. As at 31 August 2024, net debt was US$94.6 million, based on consolidated Group cash balances of US$105.4 million and US$200.0 million of debt drawn under the RBL facility. The Group expects to receive c.US$57 million of proceeds in September relating to August liftings. The Group's US$31.9 million working capital facility was undrawn at the end of the period.

Paul Blakeley, President and CEO commented:

"Increased production, coupled with robust price realisations and flat underlying operating costs, resulted in an improving financial performance in the first half of 2024, with adjusted EBITDAX and operating cash flows significantly higher year-on-year.

Our first half performance also benefited from the increasing diversification of the portfolio as we build greater reliability and resilience. The adverse weather which impacted our Australia production early in the year was offset by higher production from Malaysia, an increase in our CWLH interest and strong output from Sinphuhorm. Montara performance continues to improve with greater facility reliability year-to-date, and good progress on the FPSO tank and repair programme, which allowed us to release the temporary storage tanker at Montara a few months earlier than planned. We also added a medium-term growth option by signing the SFA Cluster PSC offshore Malaysia, and we continue to work hard on a gas sales agreement for our Vietnam resource.

Jadestone's primary focus so far in 2024 has been the completion and commissioning of the Akatara development project onshore Indonesia. The construction phase was completed on schedule at the end of the second quarter, followed by the start of both gas and condensate sales. Notwithstanding the current curtailment of production for a repair to the plant's refrigeration compressors, the progress at Akatara, including an excellent safety record, is a major step forward for the Group, and will diversify our cash flow generation with more low cost and high value production."

2024 FIRST HALF RESULTS SUMMARY

USD'000 except where indicated	Six months ended 30 June 2024	Six months ended 30 June 2023	Twelve months ended 31 December 2023
Total hours worked lost time injury free (million)	3.85	1.45	4.55
Total recordable injury rate	3.12	0.00	0.86
Production, boe/day[1]	16,867	12,339	13,813
Realised oil price per barrel of oil equivalent (US$/boe)[2]	88.73	86.15	87.34
Realised gas price per thousand standard cubic feet (US$/mscf)	1.64	1.41	1.53
Revenue[3]	185,060	86,660	309,200
Production costs	(136,324)	(90,650)	(232,772)
Adjusted unit operating costs per barrel of oil equivalent (US$/boe)[4]	31.72	40.27	37.24
Adjusted EBITDAX[4]	60,215	(3,127)	90,647
Loss after tax	(31,119)	(59,934)	(91,274)
Loss per ordinary share: basic and diluted (US$)	(0.06)	(0.13)	(0.18)
Operating cash flows before movement in working capital	27,946	(24,179)	36,499
Capital expenditure	47,618	23,807	115,882
Net (debt)/cash[4]	(69,131)	7,782	(3,596)

Operational and financial summary

- Zero lost time injuries in operated and non-operated assets. This involved working 3.85 million manhours in operated assets (H1 2023: 1.45 million manhours), an increase of 165% from H1 2023.
- Zero Tier 1 or Tier 2 process safety events, with a focus on pre commissioning activities at Akatara and ongoing asset integrity programs at operated assets.
- Production increased by 37% in H1 2024, reaching 16,867 boe/d, up from 12,339 boe/d in H1 2023. The increase was due to higher production from PenMal following the successful drilling campaign in late 2023, a higher working interest in the CWLH following completion of the acquisition of an additional 16.67% working interest in February 2024, full production from Sinphuhorm, acquired in February 2023, and a full period of production from Montara, compared to H1 2023 when production was shut in for much of the first quarter. These increases were partially offset by lower production at Stag compared to the prior period, impacted by extensive weather-related downtime in Q1 2024, a planned maintenance shutdown and underperformance of downhole pumps, which have required more frequent workovers than planned.
- Oil liftings totaled 2.2 mmbbls in H1 2024, more than double H1 2023 of 1.1 mmbbls, primarily driven by increased production described above and the addition of an underlift position at CWLH as part of the February 2024 acquisition, which subsequently formed part of a lifting in March 2024.
- The average oil price realisation, excluding the effect of hedging for H1 2024, was US$88.73/bbl, a 3.0% increase from US$86.15/bbl in H1 2023. This increase was driven by a higher realised Brent price, which rose by 8.9%, to US$84.14/bbl from US$77.28/bbl in H1 2023. The higher realised Brent price was offset by a reduction in the premium to US$4.59/bbl in H1 2024, from US$8.87/bbl in H1 2023. This decrease was due to the composition of liftings, with lower liftings at Stag (which attracts the highest premium of Jadestone's production), and higher lifted volumes at CWLH, which has a lower premium.
- H1 2024 revenue totalled US$185.1 million, a 113% increase on H1 2023, reflecting the increase in lifted volumes and price realisations described above. H1 2024 revenue reflects a hedging charge of US$15.4 million from commodity swap contracts entered in support of the execution of reserves-based lending ("RBL") facility;

- The CWLH 2 acquisition impacted revenues and production costs in H1 2024 by US$45.8 million (2023: Nil), reflecting the market value of the under-lift obtained after acquiring an additional 16.67% interest in the CWLH assets (combined interest 33.34%) in February 2024. The US$45.8 million in production costs is a non-cash item arising from the purchase price allocation required under acquisition accounting standards. The underlift was sold as part of the March 2024 lifting realising US$45.8 million.
- Production costs, excluding the movement in inventory and the under-lift impacts, decreased by 0.7%, from US$116.4 million in H1 2023 to US$115.5 million in H1 2024.
- As at 30 June 2024, closing crude inventories totalled 442,781 bbls, and the Group had an underlift position of 270,449 bbls. After the H1 2024 reporting period, the Group generated US$53.0 million in revenues from three liftings of 0.59 mmbbls in July from Montara, Stag and PenMal;
- Adjusted EBITDAX increased to US$60.2 million from a loss of US$3.2 million in H1 2023, mostly due to higher revenue;
- Net loss after tax in H1 2024 of US$31.1 million (H1 2023: US$59.9 million net loss);
- Operating cash flow before movements in working capital significantly improved in H1 2024 to US$27.9 million from an outflow of US$24.2 million in H1 2023, reflecting the trends described above;
- Capital expenditure in H1 2024 of US$47.6 million, an increase of 100% compared to H1 2023 (at US$23.8 million) primarily due to higher expenditure for the Akatara development project onshore Indonesia as it entered the final phase of commission and completion; and
- Net debt balance of US$69.1 million as at 30 June 2024 (H1 2023: US$7.8 million net cash), reflecting a drawdown of US$200.0 million from the RBL facility and total cash and cash equivalents of US$130.9 million.

[1] Production includes the Sinphuhorm Asset gas production in accordance with Petroleum Resource Management Systems guidelines, non-IFRS measures. However, in accordance with IAS 28 the investment is accounted for as an associated undertaking and only recognises the share of results of associate. Accordingly, the revenue and production costs from the Sinphuhorm Assets are excluded from the Group's financial results. Sinphuhorm production is included in the Group's production figures.

[2] Realised oil price represents the actual selling price inclusive of premiums, excluding the effect of hedging.

[3] Revenue in H1 2024 and YE 2023 include hedging loss of US$15.4 million and US$10.3 million respectively from the commodity swap contracts entered into in support of the RBL facility.

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

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Webcast

The Company will host an investor and analyst presentation at 9:00 a.m. (BST) on Tuesday, 17 September 2024, including a question-and-answer session, accessible through the link below:

Webcast link: https://www.investis-live.com/jadestone-energy/66c5c57a7caa6c19003474c9/maert

Event title: Jadestone Energy plc first-half 2024 results
Time: 9:00 a.m. (BST)
Date: 17 September 2024

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

United Kingdom (Local): +44 20 3936 2999
United Kingdom (Toll-Free): +44 800 358 1035
Global Dial-In Details: https://www.netroadshow.com/events/global-numbers?confId=70236
Access Code: 288973

ENVIRONMENT, SOCIAL AND GOVERNANCE ("ESG")

Jadestone is committed to being a responsible operator, that contributes to an orderly energy transition by helping to meet regional energy demand, whilst bringing positive social and economic benefits for its stakeholders, local communities and the people associated with its operations. Progress made during the half year ended 30 June 2024 is set out below across Jadestone's priority ESG areas.

HSE Governance

The Group continued its strong safety performance in the first year half of 2024 despite elevated levels of activity at the Akatara project. The Group reported no life altering events or significant impact to the environment, no regulatory enforcements notices, no Tier 1 or 2 process safety loss of primary containment events but one lost time injury (LTI). Jadestone's combined operations worked over 3.8 million manhours in H1 2024. The lost time injury related to staff sustaining a shoulder injury which required minor surgery.

Of note is the safety record at the Akatara gas development project site onshore Sumatra, Indonesia, which achieved the major milestones of mechanical completion and introduction of feed gas from wells, which signalled the commencement of commissioning activities in June 2024. The project has achieved 7.4 million manhours with no LTI reported. Commissioning saw the site transition from a construction site to a facility producing hydrocarbons, requiring a change in how work is planned and executed. As at the end of June, there had been no process safety loss of primary containment events associated with commissioning, with ongoing activities to ensure controls are effectively implemented. Whilst the site currently remains formally under the control of the EPCI contractor, a detailed Operational Readiness program has been undertaken by the Company to ensure that when the performance test is completed, and the facility is formally handed over, Jadestone Energy is ready to safely operate the facility.

The Montara Venture FPSO tank inspection and repair program has been progressing well, following a Prohibition Notice issued by the regulator in June 2022. All tanks have been inspected and repairs are ongoing. Jadestone continues to engage closely and transparently with the regulator about the progress of the inspection and repair work and as each tank is completed, a Technical File Note is issued to the regulator which allows the tank to be released from the Prohibition Notice.

Net Zero interim targets

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

The Company is committed to reduce Scope 1 and 2 absolute GHG emissions from its operated assets by 20% by 2026 and by 45% by 2030 (from 2021 levels) on its pathway to Net Zero by 2040. These interim targets will be achieved through a combination of measures, including minimising flaring, methane quantification, monitoring and reduction as well as reliance on carbon credits within the regulatory schemes of Jadestone's operating regions. For details of Jadestone's Net Zero GHG reduction plan, please refer to the 2023 Sustainability Report.

Group's H1 2024 Scope 1 GHG emissions[1] during H1 2024 were slightly below plan, due to operations at Stag being affected by monsoon activity and flaring reduction initiatives at Montara. At the Montara site, a 33% reduction on flaring emissions compared to workplan and budget was achieved in H1 2024, due to a heightened focus on minimisation of flaring during normal production as part of a three-step flare optimisation plan for Montara. This plan involves:

[1] Includes Montara, Stag and PenMal sites; Jadestone will integrate GHG emissions from the Akatara Gas field operations in the Full Year 2024 report.

- Reinjection compressor ("RIC") control logic modifications and automation of the injection choke, with the scope completed in May 2024, resulting in historically low flare rates post completion;
- Continued focus on reliability of the RIC resulting in significant improvement in RIC uptime during H1 2024;
- Feasibility analysis into increasing the capacity of the RIC. The engineering studies have commenced and will be completed during H2 2024.

These initiatives are an important cornerstone of Jadestone's Net Zero implementation roadmap to 2030.

The Company continues to build a fit-for-purpose Leak Detection and Repair programme across all operated assets and targets the introduction of annual leak detection and repair ("LDAR") at each operated site by the end of 2024[1].

Governance

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

On 25 January 2024, the Company announced the appointment of Joanne Williams as an independent non-executive director. Ms. Williams is the Chair of both the HSEC Committee and the Montara Technical Committee, and a member of the Audit Committee and the Disclosure Committee.

On 25 March 2024, the Company announced the appointment of Adel Chaouch as an independent non-executive director. On the same day, the Company announced the resignation of Lisa Stewart as an independent non-executive director and Robert Lambert as an independent non-executive director.

On 27 March 2024, the Company announced the resignation of Dennis McShane as an independent non-executive director and Chair of the Board. On the same day, the Company announced the election of Adel Chaouch as the Chairman of the Board. Mr. Chaouch is the Chairman of the Governance and Nomination Committee, and a member of the Remuneration Committee.

On 9 May 2024, the Company announced the appointment of Linda Beal as an independent non-executive director. Ms. Beal is the Chair of the Audit Committee, replacing Iain McLaren who, in line with previous announcements, did not seek re-election at the Company's Annual General Meeting and formally stepped down on 13 June 2024. Ms. Beal is a member the Governance and Nomination Committee and the Remuneration Committee.

Effective 12 June 2024, Joanne Williams and David Neuhauser joined the CEO and CFO on the Disclosure Committee.

On 3 July 2024, the Company announced that Bert-Jaap Dijkstra, Executive Director and Chief Financial Officer ("CFO"), has decided to leave the Company. Mr. Dijkstra will remain in his post during the publication of the Company's 2024 Half-Year Results and support the October 2024 redetermination of the Company's reserve-based lending facility.

The Company is currently making good progress on both appointing a replacement CFO and the ongoing search for a Chief Operating Officer.

[1] With an exception of Lemang, which will have an LDAR exercise implemented within 12 months of starting operations.

Producing assets

Australia

Montara Project (100% working interest, operator)

The Montara fields averaged 4,951 bbls/d in H1 2024, compared to 2,931 bbls/d in H1 2023. The year-on-year increase is primarily explained by Montara production being shut in during the start of 2023 until late March 2023 for repairs and maintenance activity on the Montara Venture FPSO's storage tanks.

Production during the first half of 2024 was impacted by the cyclone season early in the year, and the temporary shut in of the H6 and Swift-2 wells pending repairs. Both wells were brought back online early in the second half of 2024.

The Montara Venture FPSO tank inspection and repair programme is progressing well, resulting in increased oil storage capacity. This has allowed for the shuttle tanker operation, which had been in place to provide operational flexibility for Montara during the repair programme, to cease in late August 2024, earlier than planned.

The Group is progressing its plans to re-drill the Skua-11 well. This well is expected to boost Montara production through reinstating production from the Skua-11 well and is also targeting additional reserves in the Skua structure.

In total, three cargoes totalling c.0.8 mmbbls (H1 2023: one cargo of c.0.3 mmbbls) were lifted from Montara in the first half of 2024, with an average oil price realisation of US$88.35/bbl, excluding the effect of hedging (consisting of an average Brent price of US$83.82/bbl and average premium of US$4.53/bbl). This compares to an average realisation of US$76.05/bbl in H1 2023 (Brent US$74.69/bbl and premium US$1.36/bbl). A further lifting of c.0.2 mmbbls was completed in early July 2024.

CWLH (33.33% working interest)

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 ("CWLH") offshore western Australia, doubling its working interest to 33.33%.

During the first half of 2024, Jadestone's net production from the CWLH fields averaged 2,951 bbls/d, compared to 1,569 bbls/d in H1 2023. The year-on-year change is primarily explained by the increase in the Group's working interest referenced above.

Following engagement with the CWLH joint venture, total abandonment trust fund payments associated with the acquisition of the additional 16.67% interest completed in early 2024 have been revised down to US$83.8 million. The Group contributed US$65.0 million to the CWLH Abandonment Trust Fund during H1 2024 in connection with the CWLH acquisition, with the final trust fund payment of US$18.8 million expected to be paid at the end of 2024.

The Group lifted one cargo of c.0.7 mmbbls in the first half for an average oil price realisation of US$86.39/bbl, excluding the effect of hedging (H1 2023: no liftings net to the Jadestone) based on a Brent price of US$85.49/bbl with a premium of US$0.90/bbl. Due to the acquisition of an additional 16.67% share in CWLH and the ongoing good performance of the CWLH fields, a further cargo of c.0.7 mmbbls was lifted in August 2024.

Stag (100% working interest, operator)

The Stag field averaged 1,921 bbls/d in the first half of 2024, compared to 2,879 bbls/d in H1 2023. The first half of 2023 benefited from the onset of production of the Stag-50H and 51H wells drilled in late 2022. Stag field production in H1 2024 reflected greater than normal weather-related downtime in Q1 2024, a planned maintenance shutdown and mechanical issues in several wells which required workovers.

The Group continues to review options for further infill wells on the Stag field.

The Group sold one c.0.2 mmbbls cargo (H1 2023: two cargoes totalling c.0.5 mmbbls) of Stag crude in the first half of 2024. Premiums for Stag crude have remained robust, with the H1 2024 cargo being sold at US$101.37/bbl, based on average oil price realisation of US$85.49/bbl, excluding the effect of hedging, plus a premium of US$15.88/bbl. A further cargo of Stag crude was sold after the period end for a premium of US$10.69/bbl.

Malaysia

PM323 PSC (60% working interest, operator)

The PM323 PSC produced an average of 3,839 bbls/d net to Jadestone's working interest in H1 2024 (H1 2023: 1,667 bbls/d). The year-on-year increase is a result of the positive impact of the Group's infill drilling programme on the East Belumut field in late-2023.

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

A total of c.0.4 mmbbls (H1 2023: 0.1mmbbls) were lifted from the PM323 PSC in the first half of 2024, with an average oil price realisation of US$86.75/bbl (H1 2023: US$83.31/bbl) based on a Brent price of US$82.62/bbl (H1 2023: US$79.93/bbl) and a premium of US$4.14/bbl (H1 2023: US$3.38/bbl).

PM329 PSC (70% working interest, operator)

The PM329 PSC produced an average of 1,616 boe/d net to Jadestone's working interest in H1 2024, consisting of 1,103 bbls/d of oil and 3.1 mmscf/d of gas (H1 2023: 2,212 boe/d, consisting of 1,518 bbls/d of oil and 4.2 mmscf/d of gas). The year-on-year decrease is primarily explained by natural decline.

A total of c.0.1 mmbbls (H1 2023: 0.2mmbbls) of oil were lifted from the PM323 PSC in the first half of 2024, with an average oil price realisation of US$86.76/bbl (H1 2023: US$83.31/bbl), based on a Brent price of US$82.62/bbl (2023: US$79.93/bbl) and a premium of US$4.14/bbl (2023: US$3.38/bbl). In addition, c.0.6 bcf of gas was sold at an average realisation of US$1.64/mscf.

SFA Cluster (100% working interest, operator)

In July 2024, Jadestone was awarded a 100% participating interest in a Small Field Asset Production Sharing Contract (the "SFA Cluster PSC") offshore Peninsular Malaysia. The SFA 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. The SFA Cluster PSC contains the Penara, Puteri-Padang and North Lukut fields, assets in which Jadestone initially acquired a non-operated interest at the time of the Group's entry into Malaysia in August 2021.

Jadestone currently estimates that the SFA Cluster PSC contains c.15 mmbbls of gross 2C contingent resources. Leveraging the experience gained through the successful 2023 infill drilling campaign on the PM323 licence, Jadestone believes there is the potential for significant upside from future infill drilling across the existing SFA Cluster fields, as well as opportunities on the surrounding PM428 PSC. The Group intends to continue its technical assessment of the SFA Cluster prior to submission of 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 SFA Cluster PSC (referenced above). The PM428 PSC carries a US$0.5 million financial commitment to reprocess existing seismic and contains a number of prospects which, in a success case, could be developed through existing infrastructure currently operated by Jadestone.

Indonesia

Akatara gas development (100% working interest[1], operator)

The Akatara gas development is located within the Lemang Production Sharing Contract onshore Sumatra in Indonesia. Akatara was previously developed as an oil field, prior to being redeveloped by Jadestone to commercialise gas, condensate and LPGs reserves in shallower zones.

Development activity at Akatara peaked in the first half of 2024. The focus during the period was on completing the installation of equipment and infrastructure at Akatara Gas Processing Facility ("AGPF"), tying in the development wells, facilities and flowline, followed by pre-commissioning, commissioning and start-up activities.

The workover campaign on the five existing Akatara wells, which provide gas to the AGPF, was successfully completed during the period, with the five wells flowing at an aggregate rate of 54 mmscf/d, significantly in excess of the c.25 mmscf/d of raw feed gas required under the gas sales agreement. In addition, the 8" diameter 17km pipeline exporting gas from the AGPF was successfully tested and tied into the regional gas trunkline.

A major milestone was reached on 22 June 2024 with declaration of Mechanical Completion at the AGPF 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 into the second half of 2024, with commercial gas sales commencing on 31 July at a rate of c.4 mmscf/d, along with LPG production. During August, commercial gas sales reached c.14 mmscf/d, with production recently curtailed due to mechanical issues with the facility's refrigeration compressors, where repairs are currently underway.

[1] 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%.

Thailand

Sinphuhorm (9.52% working interest, non-operated)

During the first half of 2024, the Sinphuhorm field produced an average of 1,585 boe/d (1,565 boe/d gas and 23 bbls/d of condensate). Production for the period 23 February 2023 (when Jadestone completed the acquisition of its Sinphuhorm interest) to 30 June 2023 averaged 1,531 boe/d, or 1,083 boe/d averaged over the first half of 2023.

Activity at the field during the first half of 2024 mainly comprised a booster compression project, which aims to sustain plateau production levels over the remaining life of the concession. The booster compression project was completed at the end of May 2024.

As this is an investment in associate, the Group does not recognise its share of revenues and production costs, instead recognising its share of results of associate. Dividends of US$3.8 million were received in H1 2024 (H1 2023: no dividends received). A further dividend of US$0.8 million was distributed early July 2024 after the period end.

Pre-production assets

Vietnam

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

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 water offshore southwest Vietnam.

Following signature of the HoA, the Group commenced detailed negotiations over a fully termed GSPA, which are currently ongoing. The GSPA is also a precursor to the submission of an updated Field Development Plan for the Nam Du and U Minh fields, the approval of which is required before a Final Investment Decision can be taken. The Group is currently updating this FDP, which will specify 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 exploration well. This commitment has been extended several times from 2015 up to the end of June 2024. Historically, extension requests have been approved after expiry. An extension request was filed by the Company in February 2024 and is consistent with previous successful extensions, in that Jadestone proposes to drill this well as part of the development drilling for the Nam Du field development project.

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

FINANCIAL REVIEW

The following table provides selected financial information of the Group, which was derived from, and should be read in conjunction with, the unaudited condensed consolidated interim financial statements for the period ended 30 June 2024.

USD'000 except where indicated	Six months ended 30 June 2024	Six months ended 30 June 2023	Twelve months ended 31 December 2023
Production, boe/day[1]	16,867	12,339	13,813
Sales volume, barrels of oil equivalent (boe)	2,330,574	1,119,011	3,862,741
Realised oil price per barrel of oil equivalent (US$/boe)[2]	88.73	86.15	87.34
Gas sales, thousand standard cubic feet (mscf)	559,888	752,660	1,366,505
Realised gas price per thousand standard cubic feet (US$/mscf)	1.64	1.41	1.53
Revenue[3]	185,060	86,660	309,200
Production costs	(136,324)	(90,650)	(232,772)
Adjusted unit operating costs per barrel of oil equivalent (US$/boe)[4]	31.72	40.27	37.24
Adjusted EBITDAX[4]	60,215	(3,127)	90,647
Unit depletion, depreciation & amortisation (US$/boe)	13.02	13.15	14.14
Impairment of assets	-	-	(29,681)
Loss before tax	(29,129)	(70,275)	(102,766)
Loss after tax	(31,119)	(59,934)	(91,274)
Loss per ordinary share: basic and diluted (US$)	(0.06)	(0.13)	(0.18)
Operating cash flows before movement in working capital	27,946	(24,179)	36,499
Capital expenditure	47,618	23,807	115,882
Net (debt)/cash[4]	(69,131)	7,782	(3,596)

Benchmark commodity price and realised price

- The average oil price realisation, excluding the effect of hedging increased in H1 2024 by 3.0% to US$88.73/bbl, compared to US$86.15/bbl in H1 2023. The higher realised price was due benchmark Brent price increasing 8.9% to $84.14/bbl from $77.28/bbl in H1 2023. However, this gain was impacted by a reduction in average realised premium, which reduced to $4.59/bbl in H1 2024 from $8.87/bbl in H1 2023. This decrease was caused by the composition of liftings: Stag, with the highest premium, had lower lifting volumes, while CWLH, with a lower premium, had higher volumes lifted during the period.

[1] Production includes the Sinphuhorm Asset gas production in accordance with Petroleum Resource Management Systems guidelines, non-IFRS measures. However, in accordance with IAS 28 the investment is accounted for as an associated undertaking and only recognises dividends received. Accordingly, the revenue and production costs from the Sinphuhorm Assets are excluded from the Group's financial results. Sinphuhorm production is included in the Group's production figures.
[2] Realised oil price represents the actual selling price inclusive of premiums, excluding the effect from hedging.
[3] Revenue in H1 2024 and YE 2023 includes a hedging charge of US$15.4 million and US$10.3 million respectively from the commodity swap contracts entered into in support of the RBL facility.
[4] Adjusted unit operating cost per boe, adjusted EBITDAX and net (debt)/cash are non-IFRS measures and are explained in further detail on the Non-IFRS Measures section in this document.

Production and liftings

The average production recorded a 37% growth for H1 2024 with 16,867 boe/d compared to 12,339 boe/d in H1 2023. The overall increase of 4,528 boe/d was the result of the following factors:

- Montara's production rose by 2,020 bbl/d, reflecting the phased restart that began in March 2023, which impacted H1 2023 output. In contrast, H1 2024 benefited from a full six months of production.
- PenMal added 1,576 bbl/d following the successful PM323 infill drilling in late 2023, partially offset with natural field decrease at PM329.
- CWLH's production increased by 1,382 bbl/d following the completion of a second acquisition in February 2024, which doubled the working interest in the assets.
- Sinphuhorm contributed an additional 508 boe/d in H1 2024, benefiting from a full six months of production compared to H1 2023, when the asset was acquired in February 2023; and

The above increase was partly offset by:

- Stag decreased 958 bbls/d due to extended downtime caused by adverse weather conditions and increased workover activity due to mechanical issues in several wells which required workovers.

Lifted oil volumes were higher in H1 2024 compared to H1 2023 predominately due to:-

In mmbbls except where indicated	Six months ended 30 June 2024	Six months ended 30 June 2023	Remark
CWLH	0.7	-	One lifting immediately following the completion of second acquisition.
Montara	0.8	0.3	H1 2024 3 liftings vs H1 2023 1 lifting with phased production resumed in late March 2023.
Stag	0.2	0.5	One lifting in H1 2024 compared to two liftings in H1 2023.
PenMal	0.5	0.3	Successful drilling campaign led to higher production available for lifting nomination.
Total	**2.2**	**1.1**	H1 2024 10 liftings vs H1 2023 6 liftings.
PenMal gas sales (mmscf)	**559.9**	**752.7**	Decrease in gas sales driven by natural decline at PM329 asset.

Revenue

The Group generated gross revenues before hedging results of US$200.5 million a 131% increase over the comparable period (H1 2023: US$86.7 million).

A commodity swap hedge resulted in a charge of US$15.4 million (H1 2023: nil), resulting in net revenue of US$185.1 million in H1 2024 (H1 2023: US$86.7 million).

The period-on-period increase in total net revenues of US$98.4 million is due to:

- Higher lifted volumes, which resulted in an increase of US$111.4 million in H1 2024; inclusive of US$45.8 million from CWLH lifting of 530,484 bbls.
- Increased average oil price realisation, excluding the effect of hedging of US$88.73/bbl in H1 2024 (compared to US$86.15/bbl in H1 2023), adding US$2.6 million to revenue;
- Lower gas sales with reduced average gas price realisation of US$1.64/mscf in H1 2024 (compared to US$1.41/mscf in H1 2023) resulted in a decrease of US$0.2 million of revenue and;
- Hedging resulted in a loss of US$15.4 million in H1 2024, with no impact in H1 2023, as the program commenced in H2 2023.

Production costs

Production costs in H1 2024 totalled US$136.3 million, a 50.3% increase from US$90.7 million in H1 2023. This US$45.7 million increase was primarily driven by changes in crude inventories and partner over/under lift imbalances. If movements in crude inventory and partner over/under lift imbalances are excluded there is a increase of $0.9 million, totaling $116.4 million compared to $115.5 million in H1 2023, indicating relatively constant underlying core operational expenses as detailed below:

	H1 2024 USD'000	H1 2023 USD'000	Variance USD'000	Note
Operating costs	53,693	52,562	1,131	(i)
Workovers	10,633	9,531	1,102	(ii)
Logistics	13,956	14,743	(787)	(iii)
Repairs and maintenance	28,090	28,378	(288)	(iv)
Tariffs and transportation costs	3,656	3,035	621	(v)
Supplementary payments and royalties	6,324	7,298	(974)	(vi)
Underlift, overlift and crude inventories movement	19,972	(24,897)	44,869	(vii)
	136,324	**90,650**	**45,674**	

(i) Operating cost rose by US$1.1 million, or 2%, to US$53.7 million in H1 2024 from US$52.6 million (H1 2023). This increase between periods was mainly explained by:

- CWLH operating costs increased by US$6.5 million, reflecting the acquisition of an additional 16.67% in February 2024, resulting in a total working interest of 33.33% from that point compared to 16.67% for H1 2023.
- Stag shuttle tanker charter rates reduced by US$3.4 million compared to H1 2023.
- Montara's operating costs decreased by US$4.6 million, from US$24.4 million in H1 2023 to US$19.8 million in H1 2024. This reduction was primarily due to lower diesel consumption at the Montara in H1 2024 compared to H1 2023 which required more diesel for FPSO and operation of compressor during wells shut-in and production start-up in late March 2023.
- PenMal operating costs increase by US$2.6 million due to the rectification costs at Abu platform and additional operational expenses associated with the non-operated assets.

(ii) Workover costs increased by US$1.1 million to US$10.6 million (H1 2023: US$9.5 million), with PenMal increasing US$0.7 million to improve well integrity and performance and US$0.4 million at Stag to carried out standard replacement for underperforming downhole pumps with 6 workovers during H1 2024 compared five in H1 2023.

(iii) Logistics costs reduced by US$0.8 million to US$13.9 million (H1 2023: US$14.7 million), primarily due unavailability of helicopter for use at Montara hence lower standing cost incurred during H1 2024 by US$1.1 million, and a US$0.3 million reduction at PenMal, with decreased offshore activities at the Puteri cluster in H1 2024 compared to H1 2023.This decrease was offset by a US$0.6 million increase at Stag, caused by multiple cyclone events that necessitated more frequent use of support vessels and helicopter services compared to the same period year-ago.

(iv) Repair and maintenance ("R&M") reduced US$0.3 million to US$28.1 million (H1 2023: US$ 28.4 million) due to a net increase at Stag of US$1.7 million for one-off remedial activities carried out on its calm buoy and an export pipeline inspection offset by a decrease of US$2.0 million due to reduced activities at PenMal SFA cluster compared to the same period year-ago.

(v) Tariffs and transportation increased by US$0.7 million to US$ 3.7 million (H1 2023: US$3.0 million) predominately due to three cargo liftings from Montara in H1 2024 compared to one in H1 2023.

(vi) Supplementary payment and royalties decreased US$1.0 million mainly reflecting the net movement from PenMal of US$2.5 million mainly due to lower realised prices compared to H1 2023. These supplementary payments are based on the differential between the realised price and the escalated PSC base price. This decrease was partially offset by an US$1.5 million increase in CWLH levies due to acquisition of the additional 16.67% ownership interest.

(vii) Underlift, overlift, and crude inventory movements increased by US$44.9 million, primarily due to the purchase price accounting for the second acquisition of CWLH. The acquisition of the second tranche of CWLH increased production costs by US$45.8 million, attributable to the 530,484 bbls of underlift acquired. This underlift was sold in March 2024, and the cost associated with acquiring the crude inventory is recorded under crude inventories and partner over/under lift imbalances. As per IFRS 3 *Business Combinations*, all identifiable assets acquired in an acquisition must be valued at their fair value. In this case, the crude inventory was valued at the price achieved during the April lifting, which was US$86.28 per barrel (refer to Note 8, *Acquisition of Interest in CWLH Joint Operation*).

Adjusted unit operating cost per boe was US$31.72/bbl (H1 2023: US$40.27/bbl) (see Non-IFRS Measures section below in this document). The decrease is predominately due to increased production and a stable production cost.

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

Depletion charges for oil and gas properties increased by 73.4% to US$30.0 million in H1 2024, compared to US$17.3 million in H1 2023. This increase was primarily due to a 37% rise in production during H1 2024, higher unit rates driven by an increase in Asset Retirement Obligations (ARO), and the commencement of production from the PM323 infill wells. The depletion cost on a unit basis in H1 2024 was US$13.02/boe, a decrease of 1.0% compared to US$13.15/boe in H1 2023.

Depreciation of the Group's right-of-use assets and plant and equipment increased to US$8.2 million in H1 2024 from US$7.3 million in H1 2023, mainly due to lease changes and renewals.

Other expenses

Other expenses increased US$5.9 million during H1 2024 to US$14.3 million (H1 2023: US$8.4 million) predominately related to the recognition of a provision for two Lemang contingent payments with a combined fair value of US$5.5 million associated with the average brent price and average Saudi CP[1] exceeding US$80/bbl and USD620/MT respectively in first year of production. These two events were not recognised H1 2023 as at the time, future prices were not anticipated to exceed these forecasted prices (full details of the contingent payments were detailed in the Annual Report Note 37 *Provisions*).

Finance costs

Finance costs in H1 2024 were US$19.5 million (H1 2023: US$22.5 million), a decrease of US$3.0 million, predominately due to:

- A warrant reserve was established during the 2023 equity raise, resulting in a US$6.1 million charge in that period. No corresponding charge was recorded in H1 2024.
- Lending fees decreased US$1.8 million to US$0.4 million in H1 2024, from US$2.2 million in H1 2023. This decrease primarily resulted from one-off, non-recurring fees associated with the equity raise and working capital facility in the previous period.

[1]The term "Saudi CP" typically refers to the Saudi Contract Price (CP), which is a benchmark price for liquefied petroleum gas (LPG) in the global market.

- The RBL accretion fees and interest expenses increased by US$3.0 million to US$5.5 million in H1 2024, up from US$2.5 million in H1 2023. This increase reflects higher borrowings and a full six months of expenses in H1 2024, compared to the partial period of expense incurred in H1 2023, after entering into the RBL in May 2023.
- ARO accretion expense increased by US$0.9 million to US$10.5 million in H1 2024, up from US$9.6 million in H1 2023. This increase in Asset Retirement Obligation (ARO) was primarily driven by two factors: the acquisition of additional CWLH ownership share in February 2024, and the increased percentage of completion for Lemang's EPCI project.

Other financial gains

Other financial gains in H1 2024 amounted to US$1.0 million (H1 2023: US$ nil), resulting from the revaluation of the warrant liability created during the 2023 equity raise. The warrant liability, recorded under Current Liabilities, is revalued at each reporting date. This gain reflects a reduction in the liability from US$3.5 million at year-end 2023 to US$2.5 million in H1 2024.

Taxation

The tax expense of US$2.0 million in H1 2024 (H1 2023: tax credit of US$10.3 million) comprised current tax charge of US$7.5 million (H1 2023: tax credit US$2.1 million) and a deferred tax credit of US$5.5 million (H1 2023: tax credit of US$8.2 million).

The tax charge 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:

	H1 2024 USD'000	H1 2023 USD'000
Loss before tax	**(29,129)**	**(70,275)**
Tax calculated at the domestic rates appliable to the profit/loss in the respective countries (Australia 30%, Malaysia 38% and 24% and Singapore 17%)	(4,646)	(18,100)
Less the effects of:		
Australian Petroleum Resource Rent Tax (PRRT) credit	(5,741)	(231)
Deferred PRRT tax expense	545	-
Non-deductible expenses	1,787	5,191
Deferred tax assets not recognised	7,856	4,977
Other income not subjected to tax	(482)	-
Adjustments to prior year	2,671	(2,178)
Tax expense/(credit) for the period	**1,990**	**(10,341)**

RECONCILIATION OF CASH

US$'000		H1 2024		H1 2023 Reclassified[1]
Cash and cash equivalent at the beginning of period		**153,404**		**123,329**
Revenue	185,060		86,660	
Other operating income[2]	3,525		3,324	
Production costs	(136,324)		(90,650)	
Administrative staff costs[2]	(15,541)		(15,080)	
General and administrative expenses[2]	(8,774)		(8,433)	
Operating cash flows before movements in working capital		**27,946**		**(24,179)**
Movements in working capital[1]		(40,271)		(71,377)
Net tax paid		(16,486)		(4,755)
Purchases of intangible exploration assets, oil and gas properties, and plant and equipment[3]		(27,151)		(23,439)
Cash paid for acquisition of Sinphuhorm Assets		-		(27,853)
Cash received for acquisition of additional interest 16.67% of CWLH Assets		5,236		-
Dividends received from associate		3,768		-
Interest received		410		1,466
Net proceeds from issuance of shares		-		51,070
Shares repurchased		-		(2,084)
Repayment of lease liabilities		(7,658)		(7,009)
Total drawdown from borrowings		43,000		161,000
Repayment of borrowings		-		(50,000)
Repayment of costs and interest of borrowings		(8,394)		(793)
Other financing activities		(2,935)		(6,594)
Total cash and cash equivalent at the end of period		**130,869**		**118,782**

NON-IFRS MEASURES

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

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

[1] Certain H1 2023 comparative information has been reclassified. The placement of decommissioning trust fund for the CWLH Assets are now reclassified from investing activities to working capital in accordance with the nature of activities.
[2] Other operating income, administrative staff costs and general and administrative expenses adjusted figures are non-IFRS measures.
[3] Total capital expenditure was US$47.6 million (H1 2023: US$23.8 million), comprising total capital expenditure paid of US$27.1 million (H1 2023: US$23.4 million), accrued capital expenditure of US$16.2 million (H1 2022: US$0.4 million) and capitalisation of borrowing costs of US$4.3 million (H1 2023: nil).

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 defined as total production costs excluding oil inventories movement and underlift/overlift, write down of inventories, workovers (to facilitate better comparability period to period) and non-recurring repair and maintenance. It includes lease payments related to operational activities, net of any income earned from leasing of right-of-use assets involved in production, and excludes transportation costs, PenMal Asset supplementary payments, costs associated with the PenMal non-operating assets and DD&A.

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

USD'000 except where indicated	Six months ended 30 June 2024	Six months ended 30 June 2023	Twelve months ended 31 December 2023
Production costs (reported)	136,324	90,650	232,772
Adjustments			
Lease payments related to operating activities[1]	8,764	7,493	16,155
Underlift, overlift and crude inventories movement[2]	(19,972)	24,897	9,297
Workover costs[3]	(10,633)	(9,531)	(17,562)
Other income[4]	(3,200)	(2,584)	(6,375)
Non-recurring operational costs[5]	(6,775)	(11,565)	(19,654)
Non-recurring repair and maintenance[6]	(5,343)	(312)	(1,773)
Transportation costs[7]	(3,656)	(3,035)	(7,502)
PenMal Assets supplementary payments and Australian royalties[8]	(6,324)	(7,298)	(16,056)
PenMal PNLP assets operational costs[9]	(994)	(6,670)	(19,273)
Adjusted production costs	**88,191**	**82,045**	**170,029**
Total production (barrels of oil equivalent)	2,780,677	2,037,420	4,566,060
Adjusted unit operating costs per barrel of oil equivalent	**31.72**	**40.27**	**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 in H1 2024 mainly related to costs incurred at Montara being interim tanker storage temporarily employed as a result of the repair work relating to the storage tanks of the FPSO.

[6] Non-recurring repair and maintenance costs in H1 2024 predominately related to floating hose repair at Montara, CALM buoy coating remediation and maintenance pigging of export flowline at Stag, and rectification costs of the cranes and platforms of PNLP asset at PenMal. The costs during H1 2023 predominately related to the repair of a gas turbine generator at the PenMal Assets PM329 PSC.

[7] Transportation costs includes the pipeline tariff at PenMal 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 include a temporary levy passed by the Australian Government on offshore petroleum production and a levy on the wellhead value of primary production licence from the CWLH Assets.

[9] Similar to H1 2023, PenMal non-operated assets operational costs in H1 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 don't contribute to production.

Adjusted EBITDAX

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

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

The calculation of adjusted EBITDAX is as follows:

USD'000	Six months ended 30 June 2024	Six months ended 30 June 2023	Twelve months ended 31 December 2023
Revenue	185,060	86,660	309,200
Production costs	(136,324)	(90,650)	(232,772)
Administrative staff costs	(15,757)	(15,538)	(30,197)
Other expenses	(14,312)	(8,446)	(22,841)
Share of results of associate	2,124	-	2,640
Other income, excluding interest income	3,528	3,324	14,404
Other financial gains	1,001	-	-
Unadjusted EBITDAX	**25,320**	**(24,650)**	**40,434**
Non-recurring			
Net loss from oil price and foreign exchange derivatives	15,425	-	10,395
Non-recurring opex[1]	13,112	18,547	40,700
Assets written off	38	-	3,067
Change in provision – Lemang PSC contingent payments	5,500	-	(7,653)
Others[2]	820	2,976	3,704
	34,895	**21,523**	**50,213**
Adjusted EBITDAX	**60,215**	**(3,127)**	**90,647**

[1] Non-recurring opex mainly 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 one-off repair and maintenance costs predominately related to CALM buoy coating remediation and maintenance pigging of export flowline at Stag, and rectification costs of the cranes and platforms of AAKBNLP asset at PenMal. The H1 2023 non-recurring costs 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.

[2] Includes business development related expenses, external funding sourcing costs, internal reorganisation costs and fair value loss on contingent consideration.

Net (debt)/cash

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

USD'000	30 June 2024	30 June 2023	31 December 2023
Borrowings (principal sum)	(200,000)	(111,000)	(157,000)
Cash and cash equivalents	130,869	118,782	153,404
Net (debt)/cash	**(69,131)**	**7,782**	**(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.

2024 PRINCIPAL FINANCIAL RISKS AND UNCERTAINTIES

The Group manages principal risks and uncertainties via its risk management framework. The Group is exposed to a variety of political, technological, environmental, operational and financial risks which are monitored and/or mitigated to acceptable levels.

The Group's risk management framework provides a systematic process for the identification of the principal risks which have the possibility of impacting the Group's strategic objectives. The Board regularly reviews the principal risks and defines corporate targets based on acceptable levels of risk. The Board assesses material risks with a full review of the risk matrix at least twice per year.

Details of the principal risks and uncertainties faced by the Group as at 30 June 2024 remain unchanged from the risks disclosed in the 2023 Annual Report pages 31 to 34. The Group's risk mitigation activities also remain unchanged.

GOING CONCERN

The Directors have adopted the going concern basis in preparing these unaudited condensed consolidated interim financial statements, having considered the principal financial risks and uncertainties of the Group.

The Directors believe that the Group is well placed to manage its financing and other business risks satisfactorily. The Directors have a reasonable expectation that the Group will have adequate resources to continue in operation for at least 18 months from the balance sheet date of these unaudited condensed consolidated interim financial statements. They therefore consider it appropriate to adopt the going concern basis of accounting in preparing these financial statements. Details of going concern are disclosed in Note 2.

STATEMENT OF DIRECTORS' RESPONSIBILITIES

The Directors confirm that to the best of their knowledge:

a. the condensed consolidated interim set of financial statements has been prepared in accordance with IAS 34 *Interim Financial Reporting*;

b. the interim management report includes a fair review of the information required by DTR 4.2.7R (indication of important events during the first six months and description of principal risks and uncertainties for the remaining six months of the year); and

c. the interim management report includes a true and fair review of the information required by DTR 4.2.8R (disclosure of related parties' transactions and changes therein).

By order of the Board,

Bert-Jaap Dijkstra
Executive Director
Chief Financial Officer
17 September 2024

CAUTIONARY STATEMENT

This Interim Management Report (IMR) has been prepared solely to provide additional information to shareholders to assess the Group's strategies and the potential for those strategies to succeed. The IMR should not be relied on by any other party or for any other purpose.

The IMR contains certain forward-looking statements. These statements are made by the directors in good faith based on the information available to them up to the time of their approval of this report but such statements should be treated with caution due to the inherent uncertainties, including both economic and business risk factors, underlying any such forward-looking information.

Condensed Consolidated Statement of Profit or Loss and Other Comprehensive Income for the six months ended 30 June 2024

	Notes	Six months ended 30 June 2024 Unaudited USD'000	Six months ended 30 June 2023 Unaudited USD'000	Twelve months ended 31 December 2023 Audited USD'000
Consolidated statement of profit or loss				
Revenue		185,060	86,660	309,200
Production costs	4	(136,324)	(90,650)	(232,772)
Depletion, depreciation and amortisation	4	(38,180)	(24,574)	(76,141)
Administrative staff costs		(15,757)	(15,538)	(30,197)
Other expenses	4	(14,312)	(8,446)	(22,841)
Impairment of oil and gas properties		-	-	(29,681)
Share of results of associate	11	2,124	-	2,640
Other income		6,779	4,790	18,855
Finance costs	5	(19,520)	(22,517)	(41,829)
Other financial gains		1,001	-	-
Loss before tax		**(29,129)**	**(70,275)**	**(102,766)**
Income tax (expense)/credit	6	(1,990)	10,341	11,492
Loss for the period/year		**(31,119)**	**(59,934)**	**(91,274)**
Loss per ordinary share				
Basic and diluted (US$)	7	(0.06)	(0.13)	(0.18)
Other comprehensive loss				
Loss for the period/year		(31,119)	(59,934)	(91,274)
Items that may be reclassified subsequently to profit or loss:				
Loss on unrealised cash flow hedges		(34,440)	(10,985)	(30,509)
Hedging loss reclassified to profit or loss		15,425	-	10,322
		(19,015)	**(10,985)**	**(20,187)**
Tax credit relating to components of other comprehensive loss		5,704	2,160	6,056
Other comprehensive loss		**(13,311)**	**(8,825)**	**(14,131)**
Total comprehensive loss for the period/year		**(44,430)**	**(68,759)**	**(105,405)**

Condensed Consolidated Statement of Financial Position as at 30 June 2024

	Notes	30 June 2024 Unaudited USD'000	30 June 2023 Unaudited Restated* USD'000	31 December 2023 Audited USD'000
Assets				
Non-current assets				
Intangible exploration assets	9	80,440	78,730	79,564
Oil and gas properties	10	480,189	429,548	457,202
Plant and equipment	10	10,508	7,329	10,462
Right-of-use assets	10	22,462	37,980	31,099
Investment in associate	11	25,007	27,853	26,651
Other receivables and prepayment	12	262,493	191,127	141,860
Deferred tax assets		45,678	16,688	26,774
Cash and cash equivalents	13	1,356	1,000	1,008
Total non-current assets		**928,133**	**790,255**	**774,620**
Current assets				
Inventories		56,243	47,818	33,654
Trade and other receivables	12	33,354	72,716	124,379
Tax recoverable		4,801	8,496	4,085
Cash and cash equivalents	13	129,513	117,782	152,396
Total current assets		**223,911**	**246,812**	**314,514**
Total assets		**1,152,044**	**1,037,067**	**1,089,134**
Equity and liabilities				
Equity				
Capital and reserves				
Share capital	14	456	456	456
Share premium account	14	51,827	51,827	51,827
Merger reserve	15	146,270	146,270	146,270
Share based payments reserve		27,889	27,365	27,673
Capital redemption reserve	16	24	24	24
Hedging reserve	17	(27,442)	(8,825)	(14,131)
Accumulated losses		(189,468)	(127,009)	(158,349)
Total equity		**9,556**	**90,108**	**53,770**

*Certain H1 2023 comparative information has been restated. Please refer to Note 26.

	Notes	30 June 2024 Unaudited USD'000	30 June 2023 Unaudited Restated* USD'000	31 December 2023 Audited USD'000
Non-current liabilities				
Provisions	18	682,915	581,625	503,170
Borrowings	19	169,135	82,194	147,313
Lease liabilities		10,353	24,818	18,746
Other payable	20	17,337	29,014	16,966
Derivative financial instruments	21	5,897	6,386	6,708
Deferred tax liabilities		71,556	73,628	65,829
Total non-current liabilities		**957,193**	**797,665**	**758,732**
Current liabilities				
Borrowings	19	29,829	22,802	7,260
Lease liabilities		14,192	14,107	14,118
Trade and other payables	20	88,381	73,752	113,979
Derivative financial instruments	21	35,762	4,599	17,977
Warrants liability	22	2,541	6,147	3,469
Provisions	18	11,994	16,941	108,525
Tax liabilities		2,596	10,946	11,304
Total current liabilities		**185,295**	**149,294**	**276,632**
Total liabilities		**1,142,488**	**946,959**	**1,035,364**
Total equity and liabilities		**1,152,044**	**1,037,067**	**1,089,134**

*Certain H1 2023 comparative information has been restated. Please refer to Note 26.

Condensed Consolidated Statement of Changes in Equity for the six months ended 30 June 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	Accumulated losses USD'000	Total USD'000
As at 1 January 2023 (Restated)*	339	983	146,270	26,907	21	-	(64,991)	109,529
Loss for the period	-	-	-	-	-	-	(59,934)	(59,934)
Other comprehensive loss for the period	-	-	-	-	-	(8,825)	-	(8,825)
Loss for the period, representing total comprehensive loss for the period	**-**	**-**	**-**	**-**	**-**	**(8,825)**	**(59,934)**	**(68,759)**
Share-based payments	-	-	-	458	-	-	-	458
Shares issued (Note 14)	120	52,846	-	-	-	-	-	52,966
Transaction costs associated with issuance of shares (Note 14)	-	(2,002)	-	-	-	-	-	(2,002)
Shares repurchased (Note 14)	(3)	-	-	-	3	-	(2,084)	(2,084)
Total transactions with owners, recognised directly in equity	**117**	**50,844**	**-**	**458**	**3**	**-**	**(2,084)**	**49,338**
As at 30 June 2023 (Restated)*	**456**	**51,827**	**146,270**	**27,365**	**24**	**(8,825)**	**(127,009)**	**90,108**

*Certain H1 2023 comparative information has been restated. Please refer to Note 26.

	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	Accumulated losses USD'000	Total USD'000
As at 1 January 2023 (*Restated)	339	983	146,270	26,907	21	-	(64,991)	109,529
Loss for the year	-	-	-	-	-	-	(91,274)	(91,274)
Other comprehensive loss for the year	-	-	-	-	-	(14,131)	-	(14,131)
Loss for the year, representing total comprehensive loss for the year	**-**	**-**	**-**	**-**	**-**	**(14,131)**	**(91,274)**	**(105,405)**
Share-based payments	-	-	-	766	-	-	-	766
Shares issued (Note 14)	120	52,846	-	-	-	-	-	52,966
Transaction costs associated with issuance of shares (Note 14)	-	(2,002)	-	-	-	-	-	(2,002)
Shares repurchased (Note 14)	(3)	-	-	-	3	-	(2,084)	(2,084)
Total transactions with owners, recognised directly in equity	**117**	**50,844**	-	**766**	**3**	**-**	**(2,084)**	**49,646**
As at 31 December 2023	**456**	**51,827**	**146,270**	**27,673**	**24**	**(14,131)**	**(158,349)**	**53,770**

*Certain H1 2023 comparative information has been restated. Please refer to Note 26.

	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	Accumulated losses USD'000	Total USD'000
As at 1 January 2024	456	51,827	146,270	27,673	24	(14,131)	(158,349)	53,770
Loss for the period	-	-	-	-	-	-	(31,119)	(31,119)
Other comprehensive loss for the period	-	-	-	-	-	(13,311)	-	(13,311)
Loss for the period, representing total comprehensive loss for the period	**-**	**-**	**-**	**-**	**-**	**(13,311)**	**(31,119)**	**(44,430)**
Share-based payments	-	-	-	216	-	-	-	216
Total transactions with owners, recognised directly in equity	**-**	**-**	**-**	**216**	**-**	**-**	**-**	**216**
As at 30 June 2024	**456**	**51,827**	**146,270**	**27,889**	**24**	**(27,442)**	**(189,468)**	**9,556**

Condensed Consolidated Statement of Cash Flows for the six months ended 30 June 2024

	Notes	Six months ended 30 June 2024 Unaudited USD'000	Six months ended 30 June 2023 Unaudited Reclassified* USD'000	Twelve months ended 31 December 2023 Audited USD'000
Operating activities				
Loss before tax		(29,129)	(70,275)	(102,766)
Adjustments for:				
Depletion, depreciation and amortisation	4 / 10	38,180	24,574	76,141
Finance costs	5	19,520	22,517	41,829
Impairment of oil and gas properties		-	-	29,681
Assets written off		38	-	5,114
Share-based payments		216	458	766
Allowance for slow moving inventories		-	13	655
Change/(reversal of) in provision		5,500	-	(7,653)
Interest income		(3,251)	(1,466)	(4,451)
Share of result of associate	11	(2,124)	-	(2,640)
Other financial gains		(1,001)	-	-
Unrealised foreign exchange loss		(3)	-	(177)
Operating cash flows before movements in working capital		**27,946**	**(24,179)**	**36,499**
Increase in trade and other receivables		(27,286)	(77,158)	(80,900)
Decrease/(increase) in inventories		29,377	(18,630)	(15,655)
(Decrease)/increase in trade and other payables		(42,362)	24,411	62,392
Cash (used in)/generated from operations		**(12,325)**	**(95,556)**	**2,336**
Net tax paid		(16,486)	(4,755)	(14,461)
Net cash used in operating activities		**(28,811)**	**(100,311)**	**(12,125)**
Investing activities				
Cash paid for acquisition of Sinphuhorm Assets	11	-	(27,853)	(27,853)
Cash received for acquisition of additional interest 16.67% of CWLH Assets	8	5,236	-	-
Payment for oil and gas properties	10	(26,362)	(22,703)	(107,500)
Payment for plant and equipment	10	(291)	(302)	(516)
Payment for intangible exploration assets	9	(498)	(434)	(1,508)
Dividend received from associate	11	3,768	-	3,842
Interest received		410	1,466	4,451
Net cash used in investing activities		**(17,737)**	**(49,826)**	**(129,084)**

*Certain H1 2023 comparative information has been reclassified. Please refer to Note 26.

	Notes	Six months ended 30 June 2024 Unaudited USD'000	Six months ended 30 June 2023 Unaudited Reclassified* USD'000	Twelve months ended 31 December 2023 Audited USD'000
Financing activities				
Net proceeds from issuance of shares		-	51,070	50,964
Shares repurchased		-	(2,084)	(2,084)
Total drawdown from borrowings		43,000	161,000	232,000
Repayment of borrowings		-	(50,000)	(75,000)
Interest on borrowings paid		(8,252)	(793)	(5,007)
Borrowing costs paid		-	(5,535)	(7,595)
Commitment fees of borrowings paid		(142)	-	(658)
Repayment of lease liabilities		(7,658)	(7,009)	(14,400)
Interest on lease liabilities paid		(1,319)	(1,027)	(2,771)
Other interest and fees paid		(1,616)	(32)	(4,165)
Net cash generated from financing activities		**24,013**	**145,590**	**171,284**
Net (decrease)/increase in cash and cash equivalents		**(22,535)**	**(4,547)**	**30,075**
Cash and cash equivalents at beginning of the period/year		153,404	123,329	123,329
Cash and cash equivalents at end of the period/year	13	**130,869**	**118,782**	**153,404**

*Certain H1 2023 comparative information has been reclassified. Please refer to Note 26.

Explanation Notes to the Condensed Consolidated Interim Financial Statements for the six months ended 30 June 2024

1. GENERAL INFORMATION

Jadestone Energy plc (the "Company" or "Jadestone") is an oil and gas company incorporated and registered in England and Wales. The Company's registration number is 13152520. The Company is the ultimate parent company of all Jadestone subsidiaries (the "Group").

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

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

The Group is engaged in production, development, exploration and appraisal activities in Australia, Malaysia, Vietnam, Indonesia and Thailand. The Group's producing assets are in the Vulcan (Montara) basin, Carnarvon (Stag) basin and Cossack, Wanaea, Lambert, and Hermes (CWLH) oil fields, located in offshore of Western Australia, the East Piatu, East Belumut, West Belumut and Chermingat fields, located in shallow water in offshore Peninsular Malaysia and in the Sinphuhorm gas 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. The registered office of the Company is 6th Floor, 60 Gracechurch Street, London, EC3V 0HR United Kingdom.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PREPARATION

The annual financial statements of the Jadestone Energy plc will be prepared in accordance with United Kingdom adopted International Accounting Standards. The condensed set of consolidated financial statements included in this half-yearly financial report has been prepared in accordance with United Kingdom adopted International Accounting Standard 34 'Interim Financial Reporting'.

These unaudited condensed consolidated interim financial statements do not comprise statutory accounts within the meaning of section 435 of the Companies Act 2006 ("the Act"). They do not contain all disclosures required by IFRS for annual financial statements and should be read in conjunction with the Group's audited consolidated financial statements for the year ended 31 December 2023. The information for the year ended 31 December 2023 does not constitute statutory accounts as defined in section 434 of the Companies Act 2006. A copy of the statutory accounts for that year has been delivered to the Registrar of Companies. The auditors reported on those accounts: their report was unqualified, did not draw attention to any matters by way of emphasis and did not contain a statement under section 498(2) or (3) of the Companies Act 2006.

These financial statements have been prepared on an historical cost basis, except for financial instruments classified as financial instruments at fair value, which are stated at their fair values, and operating leases which are stated at the present value of future cash payments.

In addition, these financial statements have been prepared using the accrual basis of accounting.

GOING CONCERN

The Directors have considered the going concern assessment period of up to 31 December 2025 (the "going concern period"). The Group regularly monitors its cash, funding and liquidity position. Near-term cash projections are revised and underlying assumptions reviewed, generally monthly, and longer-term projections are also updated regularly.

The Group's operational and financial planning is primarily based on a formal work programme and budget plan for the current year, which is assessed and finalised at the end of the prior year, and a rolling three-year plan. The work programme and budget are supplemented by regular reforecasts throughout the current year. Under the Base Case, outlined below, the Group maintains sufficient liquidity over the 18 months from the balance sheet date of these unaudited financial statements.

The going concern assessment for the next 18 months is based on oil prices in line with the range of recent spot Brent prices, the Group's current oil price hedging programme, and 2025 operational activity from the prevailing three-year plan. This has been updated to reflect the current view on 2025 activity levels, particularly the Skua-11 well on the Montara asset, which is currently planned for early 2025 and is expected to be the main element of the 2025 capital investment programme.

Downside scenarios were also constructed, to ensure that sufficient liquidity is maintained in the event of oil prices c. 20% below the assumption in the Base Case, combined with various operational riskings. Where liquidity is reduced over the going concern period in these downside scenarios, the Directors believe that several mitigating factors would be available to increase liquidity, including but not limited to an extended working capital facility, increased RBL capacity and/or reducing or deferring the Group's planned expenditure. Consequently, the Directors believe that the Group maintains sufficient liquidity over the 18 months from the date of these unaudited financial statements.

Based on this analysis and assessment, the Directors believe that the Group is well placed to manage its financing and other business risks satisfactorily. The Directors have a reasonable expectation that the Group will have adequate resources to continue in operation for at least 18 months from the date of these unaudited condensed consolidated interim financial statements. They therefore consider it appropriate to adopt the going concern basis of accounting in preparing these financial statements.

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

The Group has applied the following amendments that are relevant to the Group for the first time with effect from 1 January 2024.

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

The amendments are effective for annual periods beginning on 1 January 2024 and require prospective application. The adoption of these amendments has not resulted in changes to the Group's accounting policies.

3. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

Critical accounting judgments and key sources of estimation uncertainty

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

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

The key judgements and sources of estimation uncertainty remain the same as disclosed in Jadestone's audited consolidated financial statements for the year ended 31 December 2023.

4. OPERATING COSTS

	Six months ended 30 June 2024 Unaudited USD'000	Six months ended 30 June 2023 Unaudited USD'000	Twelve months ended 31 December 2023 Audited USD'000
Production costs	132,668	87,615	225,270
Tariffs and transportation costs	3,656	3,035	7,502
Total production costs	**136,324**	**90,650**	**232,772**
Depletion and amortisation of oil and gas properties	29,959	17,243	60,396
Depreciation of plant equipment and right-of-use assets	8,221	7,331	15,745
Total depletion, depreciation and amortisation	**38,180**	**24,574**	**76,141**
Corporate costs	14,274	8,433	17,072
Other operating expenses	38	13	5,769
Total other expenses	**14,312**	**8,446**	**22,841**

5. FINANCE COSTS

	Six months ended 30 June 2024 Unaudited USD'000	Six months ended 30 June 2023 Unaudited Reclassified* USD'000	Twelve months ended 31 December 2023 Audited USD'000
Interest expense and others	3,414	5,626	11,460
Accretion expense	16,106	10,744	26,900
Warrants expense	-	6,147	3,469
	19,520	**22,517**	**41,829**

*Certain H1 2023 comparative information has been reclassified.

6. INCOME TAX EXPENSE/(CREDIT)

	Six months ended 30 June 2024 Unaudited USD'000	Six months ended 30 June 2023 Unaudited USD'000	Twelve months ended 31 December 2023 Audited USD'000
Current tax			
Corporate tax charge/(credit)	2,677	-	(3,403)
(Over)/under provision in prior year	(689)	(2,176)	2,051
	1,988	**(2,176)**	**(1,352)**
Australian petroleum resource rent tax ("PRRT")	-	-	1,735
Malaysian petroleum income tax ("PITA")	5,518	98	10,377
	7,506	**(2,078)**	**10,760**
Deferred tax			
Corporate tax	(7,040)	(8,833)	(20,138)
PRRT	(5,196)	(231)	(4,269)
PITA	6,720	801	2,155
	(5,516)	**(8,263)**	**(22,252)**
	1,990	**(10,341)**	**(11,492)**

7. LOSS PER ORDINARY SHARE

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

	Six months ended 30 June 2024 Unaudited USD'000	Six months ended 30 June 2023 Unaudited USD'000	Twelve months ended 31 December 2023 Audited USD'000
Loss for the purposes of basic and diluted per share, being the net profit for the period attributable to equity holders of the Company	(31,119)	(59,934)	(91,274)

	Six months ended 30 June 2024 Unaudited USD'000 Number	Six months ended 30 June 2023 Unaudited USD'000 Number	Twelve months ended 31 December 2023 Audited USD'000 Number
Weighted average number of ordinary shares for the purposes of basic EPS	540,795,472	457,510,000	499,480,437
Effect of dilutive potential ordinary shares – share options	-	-	-
Effect of dilutive potential ordinary shares – performance shares	-	-	-
Effect of dilutive potential ordinary shares – restricted shares	-	-	-
Weighted average number of ordinary shares for the purposes of diluted EPS	**540,795,472**	**457,510,000**	**499,480,437**

During the current period, 66,321 (H1 2023: 6,427,966, FY2023: 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 period/year.

During the current period, 76,356 (H1 2023: 326,477, FY2023: 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 period/year.

During the current period, 293,655 (H1 2023: 445,288, FY2023: 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 period/year.

During the current period, 30,000,000 (H1 2023: 3,977,901, FY2023: 17,095,890) 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 loss for the period/year.

Loss per share (US$)	Six months ended 30 June 2024 Unaudited	Six months ended 30 June 2023 Unaudited	Twelve months ended 31 December 2023 Audited
- Basic and diluted	(0.06)	(0.13)	(0.18)

8. ACQUISITION OF INTEREST IN CWLH JOINT OPERATION

8.1 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 operators 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 that the final payment will be US$18.8 million, payable at the end of December 2024.

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 net cash receipt of US$5.2 million at completion. On 17 May 2023, the Group received approval from the National Offshore Petroleum Titles Administrator ("NOPTA") for the title transfer.

The legal transfer of ownership and control of the non-operated 16.67% working interest in the CWLH Assets occurred on the date of completion, 14 February 2024 (the "Acquisition Date"). Therefore, for the purpose of calculating the purchase price allocation, the Directors have assessed the provisional fair value of the assets and liabilities associated with the CWLH Assets as at the Acquisition Date.

8.2 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.

8.3 Fair value of consideration

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

	USD'000
Asset purchase price	9,000
Closing statement adjustments	(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.

8.4 Assets acquired and liabilities assumed at the date of acquisition

During the period, the Group has adjusted the provisional fair values of the identifiable assets and liabilities assumed as at Acquisition Date were:

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

	Provisional PPA USD'000
Asset	
Non-current asset	
Oil and gas properties (Note 10)	12,730
Deferred tax assets	19,763
Current asset	
Amount due from joint arrangement partner	194
Trade and other receivables	45,770*
	78,457
Liabilities	
Non-current liabilities	
Provision for asset restoration obligations (Note 18)	65,881
Deferred tax liabilities	17,812
	83,693
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$45.8 million, measured at the market price as at closing based on the March 2024 lifting of US$86.28/bbl. The underlift position was recognised as an expense in production cost, following a lifting which occurred in March 2024.

Due to the size, complexity and timing of the acquisition, the valuation process is ongoing and is expected to be completed in H2 2024.

8.5 Impact of acquisition on the results of the Group

The Group's H1 2024 results included US$56.4 million of revenue and US$2.5 million of after tax profit attributable to the 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 Jan 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$24.9million.

9. INTANGIBLE EXPLORATION ASSETS

	Total USD'000
Cost	
As at 1 January 2023	77,928
Additions	802[(a)]
As at 30 June 2023	**78,730**
Additions	834[(a)]
As at 31 December 2023	**79,564**
Additions	876[(a)]
As at 30 June 2024	**80,440**
Net book value	
As at 30 June 2023 (unaudited)	**78,730**
As at 31 December 2023 (audited)	**79,564**
As at 30 June 2024 (unaudited)	**80,440**

[(a)] For the purpose of the Condensed Consolidated Statement of Cash Flows, current period expenditure on intangible exploration assets of US$0.4 million remained unpaid as at 30 June 2024 (H1 2023: US$0.4 million, FY2023: US$0.1 million).

10. OIL AND GAS PROPERTIES, PLANT AND EQUIPMENT AND RIGHT-OF-USE ASSETS

	Oil and gas properties				
	Production assets USD'000	Development assets USD'000	Plant and equipment USD'000	Right-of-use assets USD'000	Total USD'000
Cost					
As at 1 January 2023 (Restated)*	693,458	36,935	11,190	49,743	791,326
Additions	1,677	21,026	302	36,827	59,832
Transfer of 50% interest in PNLP Assets	48,604	-	-	-	48,604
Written off	-	-	-	(1,584)	(1,584)
As at 30 June 2023 (Restated)*	**743,739**	**57,961**	**11,492**	**84,986**	**898,178**
Changes in asset restoration obligations	7,150	-	-	-	7,150
Transfer of 50% interest in PNLP Assets	(174)	-	-	-	(174)
Additions	30,381	60,646	214	1,330	92,571
Written off	(3,067)	-	-	(38,089)	(41,156)
Transfer	-	-	3,122	-	3,122
As at 31 December 2023	**778,029**	**118,607**	**14,828**	**48,227**	**959,691**
Additions	4,195[(a)]	42,256[(a)]	291	-	46,742
Acquisition of additional 16.67% of CWLH Assets	12,730[(b)]	-	-	-	12,730
Adjustment	-	-	-	(661)	(661)
As at 30 June 2024	**794,954**	**160,863**	**15,119**	**47,566**	**1,018,502**
Accumulated depletion, depreciation, amortisation and impairment					
As at 1 January 2023 (Restated)*	296,748	-	3,872	41,550	342,170
Charge for the period	26,800	-	291	7,040	34,131
Impairment	48,604	-	-	-	48,604
Written off	-	-	-	(1,584)	(1,584)
As at 30 June 2023 (Restated)*	**372,152**	**-**	**4,163**	**47,006**	**423,321**
Charge for the period	37,775	-	203	8,211	46,189
Impairment	29,507	-	-	-	29,507
Written off	-	-	-	(38,089)	(38,089)
As at 31 December 2023	**439,434**	**-**	**4,366**	**17,128**	**460,928**
Charge for the period	36,194	-	245	7,976	44,415
As at 30 June 2024	**475,628**	**-**	**4,611**	**25,104**	**505,343**

*Certain H1 2023 comparative information has been restated. Please refer to Note 26.

	Oil and gas properties				
	Production assets USD'000	Development assets USD'000	Plant and equipment USD'000	Right-of-use assets USD'000	Total USD'000
Net book value					
As at 30 June 2023 (unaudited) (Restated)*	**371,587**	**57,961**	**7,329**	**37,980**	**474,857**
As at 31 December 2023 (audited)	**338,595**	**118,607**	**10,462**	**31,099**	**498,763**
As at 30 June 2024 (unaudited)	**319,326**	**160,863**	**10,508**	**22,462**	**513,159**

(a) For the purpose of the Condensed Consolidated Statement of Cash Flows, current period expenditure on oil and gas properties of US$15.8 million remained unpaid as at 30 June 2024 (H1 2023: nil, 2023: US$3.4 million). Additionally, included in the oil and gas properties is the capitalisation of borrowing costs relating to the Akatara development project of US$4.3 million (H1 2023: nil, FY2023: US$2.4 million).

(b) On February 14, 2024, the Group obtained additional non-operated 16.67% working interest in Cossack, Wanaea, Lambert and Hermes oil field development (the "North West Shelf Project" or "CWLH Asset"), offshore Australia. As a result, the Group's non-operated interest in CWLH fields has increased to 33.33% (from 16.67%) as disclosed in Note 8.

*Certain H1 2023 comparative information has been restated. Please refer to Note 26.

11. INVESTMENT IN ASSOCIATE

	30 June 2024 Unaudited USD'000	30 June 2023 Unaudited USD'000	31 December 2023 Audited USD'000
At beginning of period/year	26,651	-	-
Acquisition of 9.52% non-operated interest in Sinphuhorm Assets	-	27,853	27,853
Dividends received during the period/year	(3,768)	-	(3,842)
Share of profit of the associate	2,124	-	2,640
At end of period/year	**25,007**	**27,853**	**26,651**

On 19 January 2023, the Group executed a sale and purchase agreement with Salamander Energy (S.E. Asia) Limited, an affiliate of PT Medco Energi Internasional Tbk, to acquire its interest in three legal entities, which collectively own a 9.52% non-operated interest in the producing Sinphuhorm gas field and a 27.2% interest in the Dong Mun gas discovery onshore north-east Thailand. The acquisition included a 27.2% interest in APICO LLC, which operates the Sinphuhorm concessions (E5N and EU1) and Dong Mun (L27/43). The acquisition was completed on 23 February 2023, for a cash consideration of US$27.9 million. The acquisition has an economic effective date of 1 January 2022, which meant the Group was entitled to net cash generated since effective date to completion date.

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

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

	30 June 2024 Unaudited USD'000	30 June 2023 Unaudited USD'000	30 December 2023 Audited USD'000
Current assets	29,885	32,754	39,027
Non-current assets	127,552	142,455	133,037
Current liabilities	18,343	15,501	27,048
Non-current liabilities	5,170	8,213	6,902
Revenue	38,565	22,388	59,504
Profit before tax	18,969	10,218	26,412
Profit after tax, representing total comprehensive income for the year	7,808	7,086	9,705
Proportion of the Group's ownership interest in the associate	27.2%	27.2%	27.2%
Share of profit of the associate	2,124	-	2,640
Dividends received from the associate during the year	(3,768)	-	(3,842)

12. TRADE AND OTHER RECEIVABLES

	30 June 2024 Unaudited USD'000	30 June 2023 Unaudited Restated* USD'000	31 December 2023 Audited USD'000
Current			
Trade receivables	9,274	6,388	12,533
Prepayments	6,709	7,064	5,947
Other receivables and deposits	2,334	50,945	88,005
Amount due from joint arrangement partners (net)	3,493	2,589	12,911
Underlift crude oil inventories	9,771	4,651	3,539
VAT/GST receivables	1,311	1,079	1,444
Malaysia supplementary payment receivable	462	-	-
	33,354	**72,716**	**124,379**
Non-current			
Other receivables	244,337	181,798	127,730
VAT receivables	18,156	9,329	14,130
	262,493	**191,127**	**141,860**
	295,847	**263,843**	**266,239**

The increase in non-current other receivables during the period reflects an additional US$65.0 million payment into the CWLH abandonment trust fund, following the acquisition of an extra 16.67% non-operated working interest in CWLH assets. Additionally, US$47.8 million was reclassified from current to non-current assets due to the deferral of decommissioning activities for the PNLP CESS funds.

*Certain H1 2023 comparative information has been restated. Please refer to Note 26.

13. CASH AND BANK BALANCES

	30 June 2024 Unaudited USD'000	30 June 2023 Unaudited USD'000	31 December 2023 Audited USD'000
Cash and bank balances, representing cash and cash equivalents in the consolidated statement of cash flows, presented as:			
Non-current	1,356	1,000	1,008
Current	129,513	117,782	152,396
	130,869	**118,782**	**153,404**

The non-current cash and cash equivalents represents the restricted cash balance of US$0.7 million (H1 2023: US$0.7 million), US$0.3 million (H1 2023: US$0.3 million) and US$0.4 million (H1 2023: nil) in relation to deposits placed for bank guarantees with respect to the PenMal Assets, Australian office building, and Indonesia office building respectively. The bank guarantees are expected to be in place for a period of more than twelve months.

As part of the RBL facility, the Group must retain an aggregate amount of principal, interest, fees and costs payable for the next two quarters in the debt service reserve account ("DSRA"). An amount of US$8.2 million was deposited into the DSRA during 2023. The DSRA is to cover every six-month period obligation of the Group, hence classified as current cash and bank balances.

14. 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	**448,353,663**	**339**	**983**
Issued during the period	94,283,543	120	50,844
Vesting of 2020 performance shares	79,327	-	-
Vesting of 2020 restricted shares	101,063	-	-
Share repurchased	(2,051,022)	(3)	-
As at 30 June 2023/31 December 2023	**540,766,574**	**456**	**51,827**
Vesting of 2021 restricted shares	50,570	-	-
As at 30 June 2024	**540,817,144**	**456**	**51,827**

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

15. 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.

16. CAPITAL REDEMPTION RESERVE

The capital redemption reserve arose from the share buyback programme launched by the Company in August 2022. It represents the par value of the shares purchased and cancelled by the Company under the share buyback programme.

17. HEDGING RESERVE

	30 June 2024 Unaudited USD'000	30 June 2023 Unaudited USD'000	31 December 2023 Audited USD'000
At beginning of the period/year	14,131	-	-
Loss arising on changes in fair value of hedging instruments during the period/year	34,440	10,985	30,509
Income tax related to loss recognised in other comprehensive income	(10,332)	(2,160)	(9,153)
Net loss reclassified to profit or loss	(15,425)	-	(10,322)
Income tax related to amounts reclassified to profit or loss	4,628	-	3,097
At end of the period/year	**27,442**	**8,825**	**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.

18. PROVISIONS

	30 June 2024 Unaudited USD'000	30 June 2023 Unaudited USD'000	31 December 2023 Audited USD'000
Non-current			
Asset restoration obligations	681,484	573,161	501,091
Others	1,431	8,464	2,079
	682,915	**581,625**	**503,170**
Current			
Asset restoration obligations	-	9,551	102,811
Others	11,994	7,390	5,714
	11,994	**16,941**	**108,525**
	694,909	**598,566**	**611,695**

The total provisions for asset restoration obligations, both current and non-current, increased by US$77.6 million during the period, primarily driven by the addition of a 16.67% non-operated working interest in the CWLH Assets, amounting to US$65.9 million, and US$1.3 million related to the Akatara gas facility. The Group also recognised an accretion expense of US$10.4 million during the period.

Additionally, US$102.8 million of ARO related to the PNLP assets was reclassified from current to non-current reflecting the deferral of activities to 2038 under the Puteri Cluster SFA PSC.

19. BORROWINGS

	30 June 2024 Unaudited USD'000	30 June 2023 Unaudited USD'000	31 December 2023 Audited USD'000
Non-current secured borrowings			
Reserve based lending facility	169,135	82,194	147,313
Current secured borrowings			
Reserve based lending facility	29,829	22,802	7,260
	198,964	**104,996**	**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[1] (which is expected later).

The borrowing base 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 of which completed in February 2024. The borrowing base as at 30 June 2024 was US$200 million. 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 RBL facility pays interest at 450 basis points over the secured overnight financing rate (SOFR), plus the applicable credit spread. The Group also pays customary arrangement and commitment fees.

On 4 March 2024, the Group executed an additional drawdown of US$43.0 million from the RBL facility and subsequently increased the loan balance to US$200.0 million for the period ending 30 June 2024, compared to a total USD$157.0 million drawdown as at 31 December 2023.

For the period ending 30 June 2024, the loans had an amortised carrying value of US199.0 million. During H1 2023, the Group incurred total accretion expenses of US$9.6 million and US$0.1 million of commitment fees, of which US$4.3 million has been capitalised as disclosed in Note 10. The net accretion expenses of US$5.3 million and US$0.1 million commitment fees were recorded as finance cost in Note 5.

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 matures on 31 December 2024. The facility carries interest of 15% on drawn amounts and 5% on undrawn amounts and can be repaid or cancelled without penalties. The standby working capital facility remained undrawn as at 30 June 2024 and at the date of signing the financial statements.

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

20. TRADE AND OTHER PAYABLES

	30 June 2024 Unaudited USD'000	30 June 2023 Unaudited USD'000	31 December 2023 Audited USD'000
Current			
Trade payables	17,268	24,539	36,056
Other payables	12,658	15,506	9,100
Accruals	54,662	32,215	56,534
Contingent payments	-	-	2,000
Malaysian supplementary payment payables	-	732	2,152
Amount due to joint arrangement partner	3,138	433	1,252
Overlift crude oil inventories	-	-	6,004
GST/VAT payables	655	327	881
	88,381	**73,752**	**113,979**
Non-current			
Other payable	16,917	29,014	16,917
Accrual	420	-	49
	17,337	**29,014**	**16,966**
	105,718	**102,766**	**130,945**

21. DERIVATIVE FINANCIAL INSTRUMENTS

The Group uses derivatives to manage its exposure to oil price fluctuations. Oil hedges are undertaken using swaps. All contracts are referenced to Dated Brent oil prices. During the period, the Group entered into commodity swaps that are designated as a cash flow hedge. All hedging undertaken during H1 2024 was deemed effective.

	30 June 2024 Unaudited USD'000	30 June 2023 Unaudited USD'000	31 December 2023 Audited USD'000
Derivative financial liabilities			
Designated as cash flow hedges			
Commodity swap	41,659	10,985	24,612
Measured at fair value through profit and loss			
Foreign exchange forward contracts	-	-	73
	41,659	**10,985**	**24,685**
Analysed as:			
Current	35,762	4,599	17,977
Non-current	5,897	6,386	6,708
	41,659	**10,985**	**24,685**

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

Contract quantity	Type of contracts	Terms	Contract price	Hedge classification	Fair value asset at 30 June 2024 Unaudited USD'000	Fair value asset at 30 June 2023 Unaudited USD'000	Fair value asset at 31 December 2023 Audited USD'000
Contracts designated as cash flow hedges							
50% of Group's planned 2PD production	Commodity swap: swap component	Oct 2023 - Sep 2025	Weighted average price of US$69.69/bbl (H1 2023: US$70.09, 2023: US$70.51)	Cash flow	41,659	10,985	24,612
Contracts that are not designated in hedge accounting relationship							
To hedge MYR162.5 million by selling MYR for USD	Foreign exchange forward contracts	Execution date: 02 February 2024	USD/MYR: 4.60	FVTPL	-	-	73

22. WARRANTS LIABILITY

On 6 June 2023, as part of the underwritten placing of additional ordinary shares, the Company entered into a warrant instrument with Tyrus Capital Event S.A.M 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.

Every half-year, management applies the Black-Scholes option-pricing model to estimate the fair value of the warrants. As of 30 June 2024, the fair value of warrants liability was US$2.5 million as compared to the fair value of warrants as of 31 December 2023 of US$3.5 million. The differences of the fair value of warrants of US$1.0 million were recorded under other financial gains in the Condensed Consolidated Statements of Profit and Loss and Other Comprehensive Income as disclosed in page 24.

23. SEGMENT INFORMATION

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

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

	Producing assets		Exploration/ development		
	Australia USD'000	SEA USD'000	SEA USD'000	Corporate USD'000	Total USD'000
Six months ended 30 June 2024 (unaudited)					
Revenue					
Liquids revenue	135,279	48,865	-	-	184,144
Gas revenue	-	916	-	-	916
	135,279	**49,781**	**-**	**-**	**185,060**
Production cost	(116,424)	(19,900)	-	-	(136,324)
DD&A	(31,850)	(6,078)	(125)	(127)	(38,180)
Administrative staff costs	(7,682)	(2,553)	(772)	(4,750)	(15,757)
Other expenses	(2,671)	(3,075)	(6,560)	(2,006)	(14,312)
Share of results of associate	-	2,124			2,124
Other income	6,293	126	11	349	6,779
Finance costs	(13,927)	(3,347)	(297)	(1,949)	(19,520)
Other financial gains	-	73	-	928	1,001
Loss before tax	**(30,982)**	**17,151**	**(7,743)**	**(7,555)**	**(29,129)**
Additions to non-current assets	70,962	48,176	47,470	-	166,608
Non-current assets	323,862	301,122	256,956	515	882,455

	Producing assets		Exploration/ development		
	Australia USD'000	SEA USD'000	SEA USD'000	Corporate USD'000	Total USD'000
Six months ended 30 June 2023 (unaudited) (Restated)*					
Revenue					
Liquids revenue	62,810	22,789	-	-	85,599
Gas revenue	-	1,061	-	-	1,061
	62,810	**23,850**	**-**	**-**	**86,660**
Production cost	(70,084)	(20,566)	-	-	(90,650)
DD&A	(23,053)	(1,257)	(113)	(151)	(24,574)
Administrative staff costs	(7,066)	(3,169)	(974)	(4,329)	(15,538)
Other expenses	(2,103)	(1,111)	(778)	(4,454)	(8,446)
Other income	4,299	56	-	435	4,790
Finance costs	(6,856)	(1,523)	(1,283)	(12,855)	(22,517)
Loss before tax	**(42,053)**	**(3,720)**	**(3,148)**	**(21,354)**	**(70,275)**
Additions to non-current assets	79,647	84,731	24,145	500	189,023
Non-current assets	405,968	200,042	139,126	28,431	773,567
Twelve months ended 31 December 2023 (Audited)					
Revenue					
Liquids revenue	240,630	66,517	-	-	307,147
Gas revenue	-	2,053	-	-	2,053
	240,630	**68,570**	**-**	**-**	**309,200**
Production cost	(185,039)	(47,733)	-	-	(232,772)
DD&A	(65,204)	(10,397)	(248)	(292)	(76,141)
Administrative staff costs	(14,550)	(5,060)	(1,773)	(8,814)	(30,197)
Other expenses	(12,652)	(3,363)	(2,319)	(4,507)	(22,841)
Impairment of assets	(17,410)	(12,271)	-	-	(29,681)
Share of results of associate	-	2,640	-	-	2,640
Other income	9,990	192	7,684	989	18,855
Finance costs	(22,611)	(6,565)	(2,274)	(10,379)	(41,829)
Loss before tax	**(66,846)**	**(13,987)**	**1,070**	**(23,003)**	**(102,766)**
Additions to non-current assets	86,403	54,576	90,611	703	232,293
Non-current assets	346,281	191,550	209,373	642	747,846

*Certain H1 2023 comparative information has been restated. Please refer to Note 26.

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

Revenue arising from producing assets relates to the Group's single customer with respect to oil sales in Australia, and a different single customer for oil and gas sales in Malaysia. There is an active market for the Group's oil and gas production.

24. CONTINGENT LIABILITIES

Commitment exploration well at block 46/07 PSC, Vietnam

The Block 46/07 PSC includes a commitment well as part of the second exploration phase which began in 2014 and has been successfully extended three times until 30 June 2024 based on the plan to incorporate the commitment well into the broader Nam Du / U Minh development project. This project is currently working towards finalizing a gas sales agreement with a Final Investment Decision expected by mid 2025. On February 6, 2024, a request for a further three-year extension was submitted to the industry regulator. This request is still pending approval. Historically, such extension applications have required significant processing time. Management remains confident that approval will be secured before the year's end. However, if the extension is not approved, the Group will be obligated to pay a minimum work commitment penalty of US$10.0 million.

25. EVENTS AFTER THE REPORTING PERIOD

Puteri Cluster SFA PSC Awards

The Group has been awarded the Puteri Cluster SFA 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 PETRONAS and the Group. With this in effect, the AAKBNLP and PM318 PSC is deemed relinquished as at 30 June 2024.

Lemang PSC, Commencement of Akatara Contractual Gas

On 22 June 2024, when the Company announced mechanical completion of the Akatara Gas Processing Facility (the "Facility") and the introduction of reservoir gas into the Facility. On 31 July 2024, following successful packing of the 17km export pipeline from the Akatara field, commercial gas sales into the regional trunkline in Sumatra commenced at a rate of c.4.0 mmscfd, or approximately 20% of the daily contracted quantity ("DCQ") under the Akatara gas sales agreement.

26. RESTATEMENT AND RECLASSIFICATION OF COMPARATIVE FIGURES

Certain comparative figures in the consolidated financial statements as at 30 June 2023 of the Group have been restated arising from a change in accounting policy as well as reclassifications to conform to the presentation in the current period and to better reflect the nature of the respective items in the Group's consolidated financial statements.

The prior period restatements as at 31 December 2022 upon the finalisation of the PPA for the acquisition of the CWLH Assets (the initial non-operated 16.67% working interest in CWLH Assets) in accordance with IFRS 3 generated associated impacts to the oil and gas properties, accumulated losses, ARO provision and overlift balances. The adjustments to the PPA values of the CWLH Assets' oil and gas properties and ARO provision on the acquisition date of 1 November 2022 resulted to the adjustment to the depletion charges and ARO accretion expense recognised in 2022 subsequent to the acquisition in the consolidated statement of profit or loss. Additionally, following the adoption of Amendments to IAS 12 *Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction* in 2023 which require the deferred tax assets and deferred tax liabilities to be presented separately in the balance sheet rather than offsetting against each other with additional exclusions have been added to the initial recognition by the IASB. The adoption of Amendments to IAS 12 has impacted the Group's recognition of deferred tax assets and liabilities associated with the oil and gas properties and ARO provision as at 31 December 2022.

Both of the above-mentioned restatement then impacted the opening and closing balances of consolidated statement of financial position as at 30 June 2023 figures.

Reclassification was made relating to inventories in transit which were reclassified from trade and other receivables to inventories. This reclassification does not have impact on the net asset balance in the consolidated statement of financial position and consolidated statement or profit or loss nor on other comprehensive income.

Both of above-mentioned restatement and reclassification have been reflected on the audited figured as of 31 December 2023.

The restatements and reclassification impact the following items:

	As previously reported USD'000	Restatements USD'000	As restated USD'000
Consolidated statement of financial position as at 30 June 2023			
Oil and gas properties	452,671	(23,123)	429,548
Deferred tax assets	2,963	13,725	16,688
Inventories	47,085	733	47,818
Trade and other receivables	73,049	(333)	72,716
Provisions - non-current	579,219	2,406	581,625
Deferred tax liabilities	71,828	1,800	73,628
Accumulated losses	(113,805)	(13,204)	(127,009)
Consolidated statement of changes in equity for the year ended 1 January 2023			
Accumulated losses	(51,787)	(13,204)	(64,991)

Additionally, reclassification made in the consolidated statement of cash flows are related to the placement of decommissioning trust fund for the CWLH Assets are now classified from investing activities to working capital in accordance with the nature of activities. The reclassification does not have impact in the consolidated statement of financial position and consolidated statement or profit or loss nor on other comprehensive income.

	As previously reported USD'000	Reclassified USD'000	As reclassified USD'000
Consolidated statement of cash flow for the six months ended 30 June 2023			
Increase in trade and other receivables	(36,158)	(41,000)	(77,158)
Placement of decommissioning trust fund for CWLH Asset	(41,000)	41,000	-

Glossary

£	British pound sterling
2P	the sum of proved and probable reserves, reflecting those reserves with 50% probability of quantities actually recovered being equal or greater to the sum of estimated proved plus probable reserves
AAKBNLP	Abu, Abu Kecil, Bubu, North Lukut, and Penara oilfields
AIM	Alternative Investment Market
ARO	Asset retirement obligations
API	American Petroleum Institute gravity
bbl	barrel
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
DD&A	depletion, depreciation and amortisation
EBITDAX	earnings before interest tax, depreciation, amortisation and exploration
FPSO	floating production storage and offloading
GHG	greenhouse gases
IFRS	International Financial Reporting Standards
LPG	Liquefied petroleum gas
mcf	thousand cubic feet of natural gas
mm	million
mmbbls	million barrels
mmboe	million barrels of oil equivalent
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
opex	operating expenditures
PETRONAS	Petroliam Nasional Berhad
PITA	Petroleum Income Tax
PRRT	Petroleum Resource Rent Tax
PSC	production sharing contract
RBL	reserves based loan
reserves	hydrocarbon resource that is anticipated to be commercially recovered from known accumulations from a given date forward
US$ or USD	United States dollar

The technical information contained in this announcement has been prepared in accordance with the June 2018 guidelines endorsed by the Society of Petroleum Engineers, World Petroleum Congress, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers Petroleum Resource Management System.

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

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