2021
FULL YEAR RESULTS AND FINAL DIVIDEND ANNOUNCEMENT

Jadestone Energy

2021 Full Year Results and Recommended Final Dividend Announcement

6 June 2022—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 today its audited consolidated financial statements (the "Financial Statements"), as at and for the financial year ended 31 December 2021, and announces a recommended final dividend of US¢1.34 per share.

Paul Blakeley, President and CEO commented:

"In a little over five years, we have transformed Jadestone from an exploration-led business into a leading independent Asia-Pacific upstream company with a significant production base, and material organic growth potential. We delivered 10% production growth in 2021, exiting the year at much higher rates, and have guided to a further 36% increase in the current year. This was on the back of a successful Montara activity programme and five months of initial contribution from the Peninsular Malaysia assets acquired during the year.

Our decision to remain unhedged has resulted in direct exposure to increasing oil prices and premiums, which are largely a consequence of structural under-investment in upstream capacity, although the distressing events in Ukraine this year are also having a clear impact. Our year-end 2021 cash position of c.US$118 million has continued to grow in the first half of 2022, with pro-forma cash balances of US$180 million at end-May 2022, which includes the proceeds for barrels lifted in May but not yet received. This cash position, and our forecast cash generation, places us in a strong position to execute our 2022 capital programme, take advantage of any high-quality additional M&A opportunities that we identify, and also to significantly increase shareholder returns. We are recommending a final dividend of US$6.25 million, a 25% increase on the second 2020 dividend, and we intend to return up to US$100 million of cash to shareholders over the next 12 months. This will be in the form of higher ordinary dividends, share buybacks and/or tender offers, starting with the recommended final 2021 dividend starting today. The actual level of shareholder returns will be influenced primarily by future oil pricing and premiums, as well as operational performance and business development activity, both organic and inorganic, over this period.

I'm very pleased to report that we have taken final investment decision on the Akatara gas field development onshore Indonesia, following necessary approvals by the Indonesian upstream regulator, with first gas on track for H1 2024. We have also seen positive signs of progress on Nam Du / U Minh in Vietnam, with potential end users of gas production from the fields being directed by the government to enter into commercial discussions with Jadestone. Progress towards completion of the Maari deal remains slow, however the New Zealand upstream regulator has confirmed that it has recommenced processing our application and we continue to respond promptly to any information requests, while working cooperatively with OMV, the seller.

Production in the first five months of 2022 has been impacted by the previously announced unplanned compressor outage at Montara and a temporary shut-in of the non-operated assets in Malaysia due to class recertification issues with the leased FPSO. As a result, production in the first part of this year has averaged c. 15,700 boe/d, although in May we have seen production rates return closer to 17,000 boe/d. We therefore still expect 2022 average production to be within the 15,500 - 18,500 boe/d guidance range, with the final outcome being influenced by ongoing activity to handle increased gas volumes at Montara (which longer-term may result in the installation of additional compression on the FPSO), the timing for production re-start from the non-operated Malaysia assets, and the outcome of the Stag infill drilling programme later this year. It is worth noting that as we continue to look for ways to further improve Montara performance, installing additional compression will not only increase oil production, but also allow for more gas to be reinjected into the Montara field, thereby reducing the amount being flared. Our unit operating expense and capital expenditure guidance are also unchanged at US$23.00-28.00/boe and US$90-105 million respectively.

We aim to marry further growth in our business with a focus on addressing our greenhouse gas profile. In early June 2022 we announced a commitment to Net Zero Scope 1 and 2 greenhouse gas emissions from our operated assets by 2040. Further detail on our asset decarbonisation pathways, with interim milestones, will be a key aspect of 2023 workstreams and we will release more news on this in due course. We believe that our corporate strategy is well-suited to the energy transition, delivering essential energy from existing discovered and producing fields, and as a responsible operator with a demonstrable track record of delivering asset performance to the highest standards, providing confidence to sellers and host governments alike.

A. Paul Blakeley
Executive Director,
President and Chief Executive Officer

2021 Summary

USD'000 except where indicated	2021	2020
Production, boe/d	12,545	11,438
Realised oil price, US$/boe[1]	74.34	44.79
Revenue[2]	340,194	217,938
Operating costs per barrel of oil equivalent (US$/boe)[3, 5]	26.22	23.10
Adjusted EBITDAX[3]	157,948	62,582
Loss after tax	(13,742)	(60,178)[4]
Loss per ordinary share: basic & diluted (US$)	(0.03)	(0.13)
Dividend per ordinary share (US¢)	1.93	1.62
Operating cash flows before movement in working capital	96,622	86,883
Capital expenditure	55,996	24,065
Outstanding debt[3]	-	7,386
Net cash[3]	117,865	82,055

Operational and financial summary

- Full year production increased by 10% to 12,545 boe/d (2020: 11,438 bbls/d), in line with expectations and the guidance range. The increase year-on-year was due to:
  - The acquisition of the Peninsular Malaysia assets ("PenMal Assets") which contributed 2,539 boe/d (based on five month's production from closing on 1 August 2021 averaged over the full year);
  - Stag production being broadly flat year-on-year at 2,359 bbls/d in 2021 (2020: 2,394 bbls/d); and
  - Montara production declining to 7,647 bbls/d (2020: 9,045 bbls/d), as natural field decline, downtime during the 2021 activity programme and an unplanned shutdown to replace critical defective valves offset the initial contribution from the successful H6 infill well;
- Revenue increased 56% to US$340.2 million (2020: US$217.9 million), a Group record, due to a 66% increase in realised prices and a 10% increase in lifted volumes;
- Jadestone's average realised price in 2021 was US$74.34/bbl (2020: US$44.79/bbl), a 66% increase year-on-year. Average realised prices included an average premium over benchmark Dated Brent of US$3.39/bbl (2020: US$4.17/bbl);
- Total lifted volumes for 2021 were aligned with production and increased 10% to 4.6 mmboe (2020: 4.2 mmbbls). A total of 17 liftings (2020: 10) were achieved, including seven liftings for a total of 0.6 mmbbls and an additional 612 mcf of gas (equivalent to 0.1 mmboe) from the PenMal Assets;
- Total production costs of US$206.5 million, significantly higher from US$105.3 million in 2020, in large part due to the contribution of the PenMal Assets of US$24.5 million, plus, the exceptional Skua well workovers programme of US$47.2 million, normal well workovers at Stag and Montara of US$19.8 million (2020: US$21.7 million) and increased repairs and maintenance ("R&M") following Project Clover of US$40.1 million (2020: US$22.5 million);
- Adjusted annualised unit operating costs[5] for 2021 were US$26.22/boe, within the guidance range, but up 14% from US$23.10/bbl in 2020, primarily due to higher routine R&M and lower production at Montara;
- Adjusted EBITDAX improved 152% to US$157.9 million compared to US$62.6 million in 2020, predominately due to higher average realised prices in 2021 and the contributions from PenMal Assets since 1 August 2021;

1 Realised price represent the actual selling price, before any impact from hedging.

2 Revenue in 2020 included hedging income of US$31.4 million, pursuant to the characterisation of the two-year capped swap programme as a cash flow hedge under IFRS 9 *Financial Instruments*. Losses realised from the 2021 swaps of US$4.6 million were recognised in other expenses, pursuant to the characterisation of the ad hoc 2021 six-month swap programme as derivative instruments measured at fair value through profit or loss. The 2021 swap programme covered a short time span (not exceeding a half yearly reporting period), whereas the capped swap programme crossed three annual reporting periods.

3 Operating costs per boe, adjusted EBITDAX, outstanding debt and net cash are non-IFRS measures and are explained on pages 16 to 18.

4 Loss after tax for 2020 included an impairment of US$50.5 million associated with capitalised intangible exploration costs at SC56, a deepwater exploration block associated with the previous management.

5 Unit operating costs per barrel of oil equivalent before workovers and movement in inventories but including net lease payments and certain other adjustments (see non-IFRS measures on page 16).

- Net loss after tax of US$13.7 million (2020: US$60.2 million loss after tax), reflecting the Skua workover costs at Montara and higher R&M expenses at both Stag and Montara. During 2020, the net loss was due to lower realised prices and the US$50.5 million impairment of the SC56 licence offshore Philippines;
- Despite the Skua workovers, operating cash flow generation in 2021 was strong at US$96.6 million, before movements in working capital, up 11% compared to 2020 of US$86.9 million;
- Capital expenditure of US$56.0 million (2020: US$24.1 million) up 133% year-on-year, primarily due to the drilling of the H6 infill well at Montara;
- Total 2021 major spending (capital expenditure and the Skua-10 & 11 workovers), of US$103.2 million, within the guidance range;
- Cash balances of US$117.9 million at 2021-year end, 32% higher compared to 2020 at US$89.4 million, benefitting from favourable realised prices in the second half of the year. Jadestone has been debt free following the final scheduled repayment of the Group's senior debt facility in Q1 2021;
- Proven and probable reserves at year-end 2021 totalled 44.7 mmboe, a 20% increase on the end-2020 figure of 37.1 mmbbls, reflecting the addition of the PenMal Assets offset by production during the year; and
- Recommended final dividend of US¢1.34/share, equivalent to a distribution of US$6.3 million. This results in total dividends of US$9.0 million in respect of 2021.

Business development

- Completion of the acquisition of PenMal Assets from SapuraOMV on 1 August 2021, for a total cash consideration of US$20.0 million, comprising a headline price of US$9.0 million plus adjustments of US$11.0 million. With an economic effective date of 1 January 2021, and taking into account cash received on completion, the Group received a cash amount of US$9.2 million at closing, net of the US$20.0 million due to SapuraOMV. In January 2022, a further US$3.0 million was paid in recognition of a contingent payment triggered by Dated Brent averaging above US$65/bbl for 2021;
- On 24 November 2021, the Group executed a settlement and transfer agreement with DP Hexindo Gemilang Jaya to acquire the remaining 10% interest in the Lemang PSC, for US$0.5 million and a waiver of unpaid amounts related to the PSC. The transfer is subject to customary approvals and is expected to complete in the third quarter of 2022;
- Jadestone's internal reorganisation completed on 23 April 2021, with Jadestone Energy plc becoming the parent company of the Group; and
- Work continued to try to close the Maari acquisition in parallel with the New Zealand Government's legislative changes to the Crown Minerals Act. Both the seller and Jadestone remain fully committed in trying to close the transaction as soon as possible.

2022 GUIDANCE

- Announced a commitment to Net Zero Scope 1 and 2 greenhouse gas ("GHG") emissions from Jadestone's operated assets by 2040;
- Production guidance of 15,500-18,500 boe/d maintained, which excludes any contribution from the pending Maari acquisition. The outcome will be determined by work to address current gas handling constraints at Montara, the timing of return of the Malaysia non-operated assets which have been offline since earlier this year, and the impact of the Stag infill programme in the second half of the year;
- 2022 guidance for unit operating costs (US$23.00 – 28.00/boe) and capital expenditures (US$90.0 – 105.0 million) maintained;
- Further inorganic growth opportunities in the Asia-Pacific region under active evaluation;
- Intention to return up to US$100.0 million of cash to shareholders over the next 12 months, in the form of ordinary dividends (including the final recommended 2021 dividend announced today), share buybacks and/or tender offers. The actual level of shareholder returns will be influenced primarily by future oil pricing and premiums, operational performance and business development activity over this period.

DIVIDEND

On 6 June 2022, the Directors recommended a final 2021 dividend of 1.34 US cents/share, equivalent to 1.07 GB pence/share based on the spot exchange rate of 0.7954, an increase of 25% compared to 2020 and equivalent to a total distribution of US$9.0 million in respect of 2021. The dividend will be paid on a gross basis, in US dollars. The timetable for the dividend payment is as follows:

- Ex-dividend date : 16 June 2022
- Record date: 17 June 2022
- Payment date: 5 July 2022

The Company's growth-oriented strategy remains unchanged; the business model is highly cash-generative, and, as a result, is fundamentally pre-disposed to providing cash returns, after allowing for organic reinvestment needs, whilst maintaining a conservative capital structure, and not unduly limiting options for further inorganic growth. The Company intends to maintain and grow the dividend over time, in line with underlying cash flow generation. The Company does not offer a dividend reinvestment plan and does not offer dividends in the form of ordinary shares.

The Group's robust financial position at the end of 2021 has strengthened further in 2022, with pro-forma cash balances of US$180.0 million at end-May 2022, which includes the proceeds for barrels lifted in May but not yet received, and no debt. After careful consideration and while remaining focused on the Group's growth strategy, Jadestone's directors believe this cash position allows for a significant increase in shareholder returns. As a result, Jadestone intends to return up to US$100.0 million of cash to shareholders over the next 12 months. This will be in the form of higher ordinary dividends, share buybacks and/or tender offers, starting with the recommended final 2021 dividend announced today. The actual structure of shareholder returns has not been finalised, while the final amount of shareholder returns will primarily depend on oil pricing and premiums going forward, as well as operational performance and business development activity, both organic and inorganic.

ENVIRONMENT, SOCIAL AND GOVERNANCE ("ESG")

As a leading oil and gas development and production company in the Asia-Pacific region, Jadestone sees an opportunity to contribute to the energy security of the region whilst striving to deliver sustainable value for all of its stakeholders in a safe, as well as environmentally and socially responsible, manner. The Group's primary focus is the acquisition of mid-life producing assets and, through additional capital investment, maximising reserves recovery, improving operating performance and reducing environmental impacts, including GHG emissions. Mitigating GHG emissions from its upstream operations a key pillar of Jadestone's strategy and of its approach to managing the climate risk exposure of the business.

The Group has committed to achieving Net Zero Scope 1 and 2 GHG emissions from its operated assets by no later than 2040.

A key element of the Net Zero commitment will be the development of an emissions reduction roadmap for major operated assets, which will inform the interim emission reduction targets for the Group, to be published by the end of 2023. Where feasible, the Net Zero roadmap will prioritise actions aimed at reducing upstream emissions in the near-term.

Environment

Jadestone proactively manages environmental impacts associated with its operations through robust environmental management systems that focus on minimising pollution and protecting water resources whilst reducing carbon footprint from its upstream activities.

Despite continual challenges presented from the global pandemic in 2021, Jadestone's maintained operational performance across most areas of environmental impacts, with zero reportable environmental incidents and no environmental high potential incidents recorded during the reporting period at its operating facilities in Australia. In 2021, Jadestone continued looking for ways to further improve its discharge quality streams. The target of combined oil-in-water ("OIW") concentrations across Stag and Montara to be less than 14mg/litre was achieved and exceeded, with combined OIW at 10mg/litre based on daily averages.

Mitigating GHG emissions from upstream operations is a key pillar of Jadestone's strategy and of its approach to managing the climate risk exposure of the business. Overall, 2021 Scope 1 GHG emissions from the Australian assets increased by 6%, when compared to 2020, against a target of 5% reduction. This increase was driven by the performance of the Montara asset. Volumes flared at Montara increased due to downtime in the gas reinjection system resulting from unplanned failure to auxiliary parts as well as production impacts resulting from drilling rig mobilisation. The latter led to extended periods of time where Montara operations had to be either fully shut in or had partial production, without associated gas re-injection. These events have been subject to thorough review to inform mitigation steps in the future.

In July 2021, Jadestone completed its acquisition of the PenMal Assets, adding two operated and two non-operated assets to its portfolio. Jadestone worked with the previous operator, as well as the upstream arm of PETRONAS, to ensure that sound HSE and asset integrity practices were sustained throughout the transition period and were further built upon following the transfer of operatorship. Going forward, Jadestone will continue to imprint its operational excellence ethos onto the new assets, work to reduce GHG emissions, manage water resources, maintain asset integrity and avoid major accidents. Jadestone's 2022 sustainability reporting will reflect the operational performance of the PenMal Assets.

Social

Jadestone strives to create a safe and rewarding working environment for its workforce and goes beyond this to recognise the positive impacts it can make within the local communities.

Jadestone continued growing its asset base throughout 2021, which is reflected in permanent employee numbers for the year increasing by 60%. The Group welcomed 108 new permanent and fixed-term employees as a result of the PenMal Assets acquisition in August 2021, with the majority of the offshore and supply base personnel engaged on the assets by the previous operator retained as Jadestone employees, while new hires were also added to the onshore team. Jadestone has a clear focus on attracting and retaining local talent across its operations, resulting in 92% of Jadestone workforce representing its local country of operations.

Over the course of 2021, Jadestone's recorded three notable personal injury incidents across its operated assets offshore Australia. These personal injury events are very significant for Jadestone, as protection of its employees is of paramount importance. The injuries were managed in accordance with the Injury & Illness Management procedure and were carefully investigated, with key learnings identified. In the context of these incidents, the rolling monthly Total Recordable Incident Frequency Rate ("TRIFR") increased accordingly and was above target for the year. Stress factors and longer shift patterns, created by uncertainty in a COVID-restricted world, were likely contributory factors and the company has largely addressed this returning to normal rosters.

In 2021, the Group enhanced community engagement programmes in all countries of operations, increasing its investment five-fold compared to the previous year, delivering tangible outcomes for the communities, which have been detailed further in Jadestone's 2021 Sustainability Report.

Governance

Jadestone's ability to create long-term value for its stakeholders is a key measurement of successful corporate governance, underpinned by high standards of business ethics and commitment to compliance. Appropriate governance is also about ensuring that the most material ESG impacts and opportunities can be acted upon, and proactively managed throughout the organisation, with the tone set by the Board of Directors (the "Board").

Jadestone's Board updated its Board Charter and committee terms of reference throughout 2021 to reflect the increasing importance of Board-level oversight over climate and wider ESG-related risks and opportunities. The Group had no incidents of violations of anti-bribery and anti-corruption laws in 2021 and has continued to maintain focus on timely regulatory approvals for new operations and growth projects, evidenced by securing gas sales agreement for the Akatara gas development in Indonesia, a key commercial milestone for the project.

Task Force on Climate-Related Financial Disclosures ("TCFD")

Throughout 2021, the Group has continued to implement the TCFD recommendations in its reporting and programmes, with a particular focus on climate risk integration and strategy considerations, commissioning a third-party to assist with conducting a climate scenario analysis across its portfolio, as well as to map out Net Zero strategic options. The Company's first climate scenario analysis helped explore potential effects of climate change on the business, corporate strategy and financial performance, by modelling the possible changes to the price of hydrocarbons due to the energy transition, and the impact of tighter carbon-related regulations through additional carbon costs associated with the International Energy Agency's climate scenarios. The results suggest that whilst some negative impact on the Group's operating cash flow would be observed, particularly in the longer-term, its portfolio and business strategy remains resilient. The detail of the climate scenario analysis is set out in the Jadestone's 2021 Sustainability Report.

Jadestone's 2021 Sustainability Report is published alongside the 2021 Annual Report. It details the Group's approach to ESG and its performance across key focus areas for the 2021 calendar year, as well as commitments to further improvements in 2022.

Operational review

Producing assets

Australia

Montara project

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

As at 31 December 2021, the Montara assets had proven plus probable reserves of 20.9mm barrels of oil, 100% net to Jadestone.

The fields produce light sweet crude (42° API, 0.067% mass sulphur), which typically sells for average Dated Brent plus the average Tapis differential in the month of lifting. The premium in 2021 ranged between US$0.43/bbl to US$2.94/bbl. Premiums have increased in the first half of 2022, with the latest Tapis Brent differential at around US$6.47/bbl.

By late September 2021, the H6 infill development well had been successfully drilled and tied into the Montara field facilities and production commenced. The well includes a circa 1,200 metre horizontal section of the reservoir in good quality oil-bearing sands. The well delivered an initial rate, after clean-up, approaching 10,000 bbls/d.

Following the completion of the H6 well, two subsea workovers on Skua-10 and 11 were performed with Skua-10 returning to stabilised production of 1,500 bbls/d. The return of production for Skua 11 was delayed to March 2022 due to required repairs on the subsea hydraulic connection, which were successfully achieved, and the well was brought back on-stream with stabilised production of 1,500 bbls/d.

Montara production averaged 7,647 bbls/d in 2021 (2020: 9,045 bbls/d). Lower production was the result of natural field decline and additional downtime associated with the drilling of H6 and the subsea workovers of Skua 10 and 11, plus an unscheduled shutdown in early 2021 to replace defective valves on the FPSO.

There were six liftings in 2021, resulting in total sales of 3.0 mmbbls, compared to 3.2 mmbbls in 2020 from the same number of liftings.

As part of Montara's three-to-four-year regular maintenance shutdown schedule, a three-week planned shutdown was originally planned for July 2022. The key workstream during this planned shutdown was the replacement of the gas turbine core, which was moved forward to February/March due to the compressor outage earlier in the year. As a result, the work scope of the planned shutdown has been significantly reduced, and all remaining critical maintenance activities can be carried out by a shorter one-week turn-around which has now been scheduled for later in 2022. Rescheduling has the added advantage of avoiding competition for labour during the Australian offshore maintenance season, and a shorter shutdown allows for maximised oil production while oil price and premiums remain high. A small amount of carry-over work may result from this but to be clear, none of this will impact on the integrity or safety of the Montara assets.

Stag oilfield

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

As at 31 December 2021, the field contained total proved plus probable reserves of 12.6mm barrels of oil, 100% net to Jadestone.

The Stag oilfield produces heavier sweet crude (18° API, 0.14% mass sulphur), which historically sells at a premium to Dated Brent. The premium in 2021 ranged between US$8.30/bbl to US$13.88/bbl. The most recent lifting was agreed at a premium of US$23.72/bbl.

During 2021, the under-buoy hose, which is used for crude oil off-loading was replaced, an undertaking which is scheduled to occur only once every five years. In addition, two extra well workovers were performed during the year compared to average, which partially reflects the clearing of a backlog of workovers which had built up in the early stages of the COVID-19 pandemic.

Production was maintained at 2,359 bbls/d in 2021, compared to 2,394 bbls/d in 2020, through ongoing production optimisation despite the constraints of COVID-19 on workover execution.

There were four liftings in 2021, for total sales of 1.0 mmbbls, compared to 0.9 mmbbls in 2020 from the same number of liftings. Asset operational and maintenance complexity was reduced through successful operation of an innovative storage tanker offloading arrangement.

A once-in-every-three-years routine shut down was conducted in Q2 2022 to perform pressure vessel inspections. In Q3 2022, the 50H and 51H infill development wells are scheduled to be drilled. These development wells are anticipated to complete and come onstream in Q4 2022, and are expected to add around 1,000 bbls/d to current production levels.

Malaysia

Operated: PM 323 and PM 329 PSCs & Non-operated: PM 318 and AAKBNLP PSCs

On 1 August 2021, Jadestone completed the acquisition of the entire share capital of SapuraOMV Upstream (PM) Inc., for a cash consideration of US$20.0 million, comprising the headline price of US$9.0 million plus adjustments of US$11.0 million.

The economic effective date of the acquisition was 1 January 2021, meaning the Group was entitled to the net cash generated since 1 January 2021 up to the completion date. As a result, on 1 August 2021 the Group obtained gross cash held by SapuraOMV of US$29.2 million, resulting in a net cash receipt of US$9.2 million.

There are two separate potential contingent payments of US$3.0 million each related to the annual average Dated Brent price exceeding US$65/bbl in 2021 and US$70/bbl in 2022. Dated Brent averaged US$70.91/bbl in 2021 and as a result the first US$3.0 million contingent payment was paid in January 2022. Management believes the second contingent payment is probable and thus recognised a discounted provision of US$1.4 million in the annual financial statements for the year ended 31 December 2021.

Post completion, the name of the acquired entity was changed to Jadestone Energy (PM) Inc. (the “PenMal Assets”).

The PenMal Assets consist of four licences, two of which are operated by the Group. The two operated licences comprise a 70% interest in the PM329 PSC, containing the East Piatu field, and a 60% interest in the PM323 PSC, which contains the East Belumut, West Belumut and Chermingat fields. Both PSCs are located approximately 230km northeast of Terengganu in shallow water. All fields are in production, and have been developed by way of fixed wellhead and central processing platforms. The two non-operated licences consist of 50% working interests in each of the PM318 PSC and in the Abu, Abu Kecil, Bubu, North Lukut, and Penara oilfields (“AAKBNLP”) PSC. The two non-operated PSCs are located in the same region as PM329 and PM323.

The PenMal Assets added immediate cash flow from 6,057 boe/d, on a net working interest basis, of which over 89% is oil. The PenMal Assets produce light sweet crude that is blended to Tapis grade (43° API, 0.04% mass sulphur).

The PenMal Assets added 11.2 mmboe net working interest 2P reserves to the Group's 2P reserves as at 31 December 2021.

The Group believes there is scope to add incremental value to the PenMal Assets in the near-term through both reservoir optimisation and production optimisation/enhancement activities across the PM323 and PM329 operated licences. Gas reinjection is expected to be a key part of reservoir optimisation. Production enhancement has been initially focused on restoring idle wells to production, while ongoing production optimisation is focused on both gas lift and topsides processes. In addition, there are infill development well opportunities at the West Belumut and East Piatu fields, which will be evaluated in parallel with the East Belumut infill potential.

In 2021, average production from the PenMal Assets since the completion date was 5,377/bbls/d of oil and 4,084 mscf/d of gas (for a total of 6,057 boe/d), net to Jadestone’s working interest. Averaged over the full year this is equivalent to 2,539 boe/d, net to Jadestone. The average realised crude oil price was US$78.29/bbl, while gas sold for US$2.19/mcf. The average premium in 2021 ranged between US$0.27/bbl to US$3.46/bbl. The most recent lifting was agreed at a premium of US$4.33/bbl.

Between the date of acquisition and the year end there were seven liftings resulting in total sales of 582,181 boe and gas sales of 624.8 mcf.

On 7 February 2022, the Bunga Kertas FPSO, deployed at the non-operated assets, had its class suspended, resulting in the fields having to shut in and temporarily cease production. The operator anticipates the FPSO will have its class reinstated by July/August 2022. Since the class suspension there has been no production from the non-operated assets.

Pending acquisition

New Zealand

Maari project

On 16 November 2019, the Group executed a sale and purchase agreement with OMV New Zealand Limited ("OMV New Zealand"), to acquire an operated 69% interest in the Maari project, located 120 km offshore New Zealand, in a water depth of 100 metres, for a total headline cash consideration of US$50.0 million and subject to customary closing adjustments.

The transaction has achieved several key milestones with regard to regulatory approvals, and the Group continues to focus on securing the remaining ministerial consents from the New Zealand Government, including the approval for transfer of operatorship.

Jadestone and OMV New Zealand continue to work towards completion of the transaction. The Group would assume the operatorship of the Maari project upon completion of the transaction. The economic benefits from 1 January 2019 until the closing date will be adjusted in the final consideration price. This is anticipated to be a net receipt to the Group.

Pre-production assets

Indonesia

Lemang PSC

The Lemang PSC is located onshore Sumatra, Indonesia. The PSC contains the Akatara field, which has been substantially de-risked with 11 wells drilled into the structure, plus three years of oil production history, up until the field ceased oil production in December 2019.

On 30 June 2021, the Minister of Mines and Energy of Indonesia issued a Ministerial decree that facilitates the development and commercialisation of the gas field, allocating gas sales from the Akatara gas field in the Lemang PSC to a subsidiary of PT Perusahaan Listrik Negara, the national electricity utility, and the associated production and sales of LPG to the local domestic market in Jambi province, together with condensate sales to a local buyer. On 1 December 2021, a gas sale agreement was signed between Jadestone and PT Pelayanan Listrik Nasional Batam, as buyer.

In early 2022, Jadestone launched a tender for the engineering, procurement, construction and installation contractor ("EPCI") for the Akatara development. After a rigorous process, a recommendation on the EPCI contractor was made to the Indonesian upstream regulator, SKKMigas, in May 2022. Regulatory approval was received in late May 2022 and the EPCI contract signed in early June 2022, allowing Jadestone to take a final investment decision ("FID") and accelerate development activity on the Akatara field.

The Akatara gas field has been independently estimated to contain a 2C gross resource (pre local government back-in rights) of 63.7 bcf of sales gas, 2.5 mmbbls of condensate and 5.6 mmboe of LPG, equating to a combined 18.7 mmboe of resource, or 16.8 mmboe net to Jadestone's existing 90% working interest. Following FID, Jadestone will book it's share of economic Akatara gas resources at the end of 2022.

Jadestone is pursuing a low-cost development of the field, including efficient re-use of existing wells and infrastructure, thereby minimising incremental impact on the local environment. The Akatara gas project remains on track for first gas in H1 2024.

On 24 November 2021, the Group announced the acquisition, subject to customary approvals, of the remaining 10% interest in the PSC from PT Hexindo Gemilang Jaya ("Hexindo"). Through this transaction, the Group's interest in the Lemang PSC will increase to 100%, pre local government back-in rights. In return for the transfer of Hexindo's 10% stake, the Group will waive unpaid amounts related to Hexindo's interest in the Lemang PSC and will pay a consideration of US$0.5 million (inclusive of transfer taxes) subject to the approval of government, shareholders of Hexindo and the shareholders of Eneco Energy Limited, Hexindo's parent company. Jadestone anticipates receiving the remaining approvals in Q3 2022.

Exploration assets

Vietnam

Block 51 and Block 46/07 PSCs

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

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

The Tho Chu discovery in Block 51 is currently under suspended development area status, with the exploration period expiring in June 2023.

The formal field development plan ("FDP") in respect of the Nam Du/U Minh development was submitted to the Vietnam regulatory authorities in late 2019. The Group deferred the project in mid-March 2020, amid delays in Vietnamese Government approvals and the drop in global oil prices due to COVID-19.

Discussions are continuing with the Vietnamese Government and Petrovietnam to reinstate the project, agree a gas production profile for the development, as a precursor to a gas sales contract, and ultimately attaining government sanction for the field development.

Philippines

Service Contract 56 ("SC56")

In 2020, Total E&P Philippines B.V. ("Total") and Jadestone informed the Philippines Department of Energy of their intention to voluntarily surrender the entire interest in SC56 (Jadestone 25% working interest) and accordingly, to terminate the contract. The effective date of termination was 21 December 2020.

Following the termination, in Q3 2021, the Group paid US$1.5 million to the Philippines Department of Energy, related to the unfulfilled minimum work programme, net to Jadestone's 25% participating interest.

Service Contract 57 ("SC57")

In 2006, the Group executed an agreement with the Philippines National Oil Company ("PNOC") to acquire a 21% working interest in SC57. The acquisition required the approval of the Office of the President of the Philippines and in December 2021 the Philippines Department of Energy advised such approval will not be granted. The Group is now seeking reimbursement from PNOC for costs of approximately US$0.9 million which it incurred in relation to a 2008 seismic acquisition campaign.

Reserves and resources

Total Proved plus Probable reserves (net, mmboe)	Australia[1]	Malaysia[2,3,4]	Indonesia	Vietnam	Total Group
Opening balance, 1 January 2021	**37.1**	**-**	**-**	**-**	**37.1**
Acquisitions	0.0	12.5	-	-	12.5
Technical revisions	0.1	0.9	-	-	1.0
Production	(3.7)	(2.2)	-	-	(5.9)
Ending balance, 31 December 2021	**33.5**	**11.2**	**-**	**-**	**44.7**

As at 31 December 2021, the Group had proved plus probable oil reserves ("2P reserves") of 44.7 mmboe, a 20% increase on the end-2020 figure of 31.7 mmbbls. The primary driver of the increase was the addition of 11.2 mmboe at year-end 2021 in respect of the PenMal Assets acquisition during the year. The combined year-on-year reduction in the reserves at the Stag and Montara fields reflected production during the year. ERC Equipoise Limited independently evaluated the Group's year-end 2021 reserves.

Total 2C Contingent Resources (net, mmboe)	Australia	Malaysia	Indonesia[5]	Vietnam[6]	Total Group
Opening balance, 1 January 2021	**-**	**-**	**16.8**	**93.9**	**110.7**
Production	-	-	-	-	-
Acquisitions	-	-	-	-	-
Technical revisions	-	-	-	-	-
Ending balance, 31 December 2021	**-**	**-**	**16.8**	**93.9**	**110.7**

The Group's best case contingent resources ("2C resources") were unchanged year-on-year at 110.7 mmboe. Of this figure, the Akatara gas field development comprises 16.8 mmboe. The Group anticipates that the Akatara gas field 2C resources will be converted to 2P reserves following development sanction of the project.

1 Proven and Probable Reserves for Jadestone's Australian assets have been prepared in accordance with the Canadian Oil and Gas Evaluation ("COGE") Handbook as the standard for classification and reporting. Jadestone does not believe that there are significant differences between the COGE standard and the 2018 guidelines endorsed by SPE, WPC, AAPG and SPEE Petroleum Resource Management System.

2 Proven and Probable Reserves for Jadestone's Malaysia assets have been prepared in accordance with the 2018 guidelines endorsed by SPE, WPC, AAPG and SPEE Petroleum Resource Management System.

3 Assumes oil equivalent conversion factor of 6,000 scf/boe.

4 The acquired 2P Reserves in Malaysia are based on an effective date of 1 January 2021. As such, the production figure of 2.2 mmboe in the table above reflects production over the calendar year 2021. Jadestone's reported production for 2021 of 12,545 boe/d includes production from the PenMal Assets from the completion of the assets (1 August 2021). The positive revision of 0.9 mmboe reflects an extension of economic life on the back of higher oil prices.

5 Lemang PSC 2C resources based on ERCE Competent Person's Report effective 31 December 2020.

6 Vietnam 2C resources based on ERCE Competent Person's Report effective 31 December 2017.

Financial review

The following table provides select financial information of the Group, which was derived from, and should be read in conjunction with, the audited consolidated financial statements for the year ended 31 December 2021.

USD'000 except where indicated	2021	2020
Sales volume, barrels of oil equivalent (boe)	4,562,279	4,165,612
Production, boe/d	12,545	11,438
Realised oil price, US$/boe[1]	74.34	44.79
Revenue[2]	340,194	217,938
Production costs	(206,523)	(105,338)
Operating costs per barrel of oil equivalent (US$/boe)[3]	26.22	23.10
Adjusted EBITDAX[3]	157,948	62,582
Unit depletion, depreciation & amortisation (US$/boe)	13.67	16.24
Impairment	-	50,455
Profit/(loss) before tax	1,080	(57,238)
Loss after tax	(13,742)	(60,178)
Loss per ordinary share: basic & diluted (US$)	(0.03)	(0.13)
Dividend per ordinary share (US¢)	1.93	1.62
Operating cash flows before movement in working capital	96,622	86,883
Capital expenditure	55,996	24,065
Outstanding debt[3]	-	7,386
Net cash[3]	117,865	82,055

1 Realised oil price represents the actual selling price and before any impact from hedging.

2 Revenue in 2020 included hedging income of US$31.4 million, pursuant to the characterisation of the two-year capped swap programme as a cash flow hedge under IFRS 9. Losses realised from the 2021 swaps of US$4.6 million were recognised in other expenses, pursuant to the characterisation of the ad hoc 2021 six-month swap programme as derivative instruments measured at fair value through profit or loss. The 2021 swap programme covered a short time span (not exceeding a half yearly reporting period), whereas the capped swap programme crossed three annual reporting periods.

3 Operating cost per boe, adjusted EBITDAX, outstanding debt and net cash are non-IFRS measures and are explained on pages 16 to 18.

Benchmark commodity price and realised price

The average benchmark price incorporated into the Group's liftings was US$70.94/bbl in 2021, an increase of 75% compared to 2020 at US$40.61/bbl.

The actual average realised price in 2021 increased broadly in line with the benchmark price, by 66% to US$74.34/bbl, compared to US$44.79/bbl in 2020. The average premium for the year was US$3.39/bbl, compared to 2020 of US$4.17/bbl. The decline in premiums was predominately due to the inclusion of PenMal Assets barrels with an average premium of $1.14bbl. Stag averaged US$11.20/bbl (2020:11.45/bbl) and Montara US$1.14/bbl (2020: US$2.04/bbl).

Since the December 2021 year end, premiums have continued to increase with the most recent liftings achieving a premium of US$6.47/bbl, US$23.72/bbl and US$4.33/bbl, at Montara, Stag and PenMal Assets respectively.

Production and liftings

The Group generated average production of 12,545 boe/d in 2021, compared to 11,438 bbls/d in 2020. Production increased due to the acquisition of PenMal Assets which generated average production of 6,057 boe/d since the date of acquisition, or 2,539 boe/d averaged over the full year. Montara production declined in 2021 to 7,647 bbls/d from 9,045 bbls/d in 2020 due to natural field decline and downtime associated with the drilling of H6 and workovers on Skua 10 & 11, plus an unscheduled shutdown to replace defective valves on the FPSO. Stag production in 2021 was 2,359 bbls/d, broadly in line with the 2,394 bbls/d achieved in 2020.

The Group had 17 liftings during the year (2020: 10), resulting in sales of 4.6 mmbbls (2020: 4.2 mmbbls), reflecting the higher production compared to 2020. The PenMal Assets contributed seven oil liftings since August, representing 0.6 mmbbls. In addition, PenMal Assets produced and sold 624.8 mcf (approximately 0.1 mmboe) of natural gas, which is sold via pipeline directly to PETRONAS.

Revenue

The Group generated revenue of US$340.2 million in 2021, an increase of 56% compared to 2020 of US$217.9 million, and the highest revenue ever recorded by the Group. The increase of US$122.3 million was predominately due to:

- Higher average realised prices in 2021, compared to 2020 for Stag and Montara, contributing an additional US$115.3 million;
- PenMal Assets generating oil revenues of US$45.6 million and gas sales of US$1.0 million (2020: nil);
- A decrease of 0.2 mmbbls in lifted volumes at Montara and Stag in 2021 compared to 2020, resulting in a decline in revenues of US$8.3 million; and
- Hedging income was nil[1] in 2021, a decline of US$31.4 million compared to 2020. The Group's 24 month capped swap cash flow hedge programme ended on 30 September 2020.

Production costs

Production costs increased by 96% in 2021 to US$206.5 million, from US$105.3 million in 2020, predominately due to:

- Workover costs of US$67.0 million (2020: US$21.7 million), mostly related to the subsea workovers at Skua 10 & 11 of US$47.2 million. The Montara subsea workovers were a one-off event and differ from the pump replacements at Stag as they require a dedicated drilling rig, whereas the Stag workovers are undertaken by the hydraulic workover unit in place on the Stag platform. There were nine workovers at Stag in 2021, compared to eight in 2020;
- Repairs and maintenance costs of $45.2 million, compared to US$22.5 million in 2020, with the PenMal Assets contributing US$5.1 million and Australia an additional of US$17.6 million compared to 2020. Montara incurred an additional US$11.6 million due to a once-in-every-three-year subsea flowline inspection, a subsea control module ("SCM") change-out on the Swift North well and higher fabric maintenance costs. Stag incurred an additional US$6.0 million due to a once-in-every-five-years under-buoy hose replacement and also higher fabric maintenance costs;
- Operating costs increased to US$61.6 million (2020: US$45.2 million), with the PenMal Assets contributing US$11.2 million, plus higher contractor charges at Stag and Montara from changing rosters in response to COVID-19 restrictions;
- Logistics costs increased to US$20.2 million (2020: US$18.9 million), with the PenMal Assets contributing US$2.3 million;
- Transportation costs of US$2.8 million in 2021 (2020: nil), reflecting the change in offtake arrangements at Stag following the cancellation of the Dampier Spirit FSO lease in September 2020. The revised offtake arrangements in Q4 2020 and through 2021 resulted in a change to the point of sale, with end buyers predominately located in Singapore and Malaysia, which resulted in the Group paying transportation expenses; and
- A net inventory movement of US$12.5 million (2021: US$9.7 million; 2020: credit of US$2.8 million), reflecting the year-on-year differential of the Group's crude inventories on hand and the change in net underlift/overlift position of the Group at year end due to production imbalances with the joint operating partner in the PenMal Assets. There were 274,103 bbls on hand at 2021 year end, compared to 601,999 bbls at 2020 year end, contributing to US$9.0 million. Additionally, the Group has a net underlift of 88,398 bbls from PenMal Assets at year end, compared to 135,115 bbls on the acquisition date, contributing to US$3.5 million.

Unit operating costs per barrel of oil equivalent were US$26.22/boe (2020: US$23.10/bbl), before workovers and movement in inventories, but including net lease payments and certain other adjustments (see non-IFRS measures below). Unit costs increased due to the lower production at Montara and higher operating costs including repairs & maintenance.

1 The hedging loss in 2021 of US$4.6 million was recognised within other expenses, as opposed to offsetting against revenue, due to the adoption of a different accounting treatment for the 2021 commodity swap contracts. The two-year capped swap programme was characterised as a cash flow hedge under IFRS 9 and realised gains were recognised as part of revenue. Losses realised from the 2021 swaps were recognised in other expenses, pursuant to the characterisation of the ad hoc 2021 six-month swap programme as derivative instruments measured at fair value through profit or loss. The 2021 programme covered a short time span (not exceeding a half yearly reporting period), whereas the capped swap programme crossed three annual reporting periods.

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

DD&A charges were US$80.2 million in 2021, compared to US$84.6 million in 2020, reflecting lower production at Montara during the year, resulting in a decrease in depletion charges in Australia of US$9.0 million compared to 2020. The reduction was partly offset by depletion charges at the PenMal Assets of US$3.6 million since the date of acquisition of 1 August 2021.

Depreciation of the Group's right-of-use assets declined by US$5.0 million mostly due to the termination of the Dampier Spirit leased FSO at Stag in 2020.

The depletion cost on a unit basis was US$13.67/boe in 2021 (2020: US$16.24/bbl), predominately due to the inclusion of PenMal Assets which lowered the average DD&A unit charge. The combined depletion cost on a unit basis at both Stag and Montara remained largely comparable to 2020 (2021: US$16.16/bbl; 2020: US$16.24/bbl). The PenMal Assets, by comparison, recorded unit depletion charges of US$3.87/boe.

Staff Costs

Total staff costs were US$51.8 million in 2021, comprising US$26.8 million (2020: US$20.7 million) in relation to offshore employees, which are recorded under production costs, and US$25.1 million (2020: US$21.9 million) associated with administrative employees. The average number of employees employed by the Group during the year was 278 (2020: 210), reflecting the additional employees associated with the acquisition of the PenMal Assets.

Other expenses

Other expenses decreased in 2021 to US$26.2 million (2020: US$26.9 million). The variance of US$0.7 million was predominately due to:

- Reduction of non-recurring costs by US$9.2 million compared to 2020. In 2021, the Group incurred total non-recurring costs of US$5.2 million, these included internal reorganisation costs of US$1.1 million, acquisition costs of US$0.8 million in relation to the PenMal Assets, and several other business development related expenses of US$3.3 million. In comparison, the Group had a total of US$14.4 million of one-off costs in 2020, including US$9.1 million associated with the litigation fees in respect of SC56 and the exit from the Block 05-1 PSC offshore Vietnam (see 'Other income' section for the litigation income generated), Australian rig contract deferral costs of US$3.0 million, Australian exploration expense of US$1.0 million and several business development projects totalling US$1.3 million, including the acquisition of the Lemang PSC;
- Net foreign exchange loss of US$1.0 million (2020: US$2.6 million);
- A fair value loss on commodity swaps of US$4.6 million (2020: US$0.5 million) pursuant to the characterisation of the ad-hoc 2021 six-month swap programme as derivative instruments measured at fair value through the profit and loss;
- Written off of intangible exploration assets of US$5.3 million (2020: nil) following the termination of a contract with a third-party contractor; and
- Higher provision made for slow-moving materials and spares on hand of US$2.6 million (2020: US$0.1 million), mainly associated with the Australian drilling components and facility spare parts.

Other income

Other income of US$7.7 million was generated during 2021 compared to 2020 of US$26.4 million. The income is predominately the result of non-recurring transactions as detailed below:

- During 2021, the Group incurred US$2.5 million of net foreign exchange gains (2020: US$0.1million) associated with the weakening of the Australian dollar;
- Rebate income of US$4.5 million (2020: US$3.6 million) arising from the sublease of right-of-use assets under the Group's helicopter lease contract;
- In comparison, during 2020, the Group generated US$11.1 million of litigation income from Total regarding the carried exploration well at SC56 for US11.1 million and received a settlement sum of US$1.0 million from Inpex regarding the litigation resolution of Block 05-1 (see 'Other expenses' section for the litigation fees incurred); and
- Also, 2020 saw the reversal of provisions associated with the Dampier Spirit of US$6.4 million and a fair value gain on derivatives of US$3.8 million.

Impairment

In 2020, the Group recorded an impairment of US$50.5 million associated with the capitalised intangible exploration costs at SC56, as the costs were no longer deemed recoverable, following the decision to voluntarily relinquish the Group's interest in the block. The impairment provision was formally written off during 2021 following the finalisation of the settlement for unfulfilled minimum work commitments under the PSC for US$1.5 million, payable to the Department of Energy in the Philippines. The penalty was offset against a prior provision of US$1.8 million resulting in a credit to other income of US$0.3 million.

Taxation

The tax charge of US$14.8 million in 2021 (2020: US$2.9 million) is split between a current tax charge of US$7.3 million (2020: US$11.7 million) and a deferred tax charge of US$7.5 million (2020: credit US$8.7 million). The current tax charge includes US$9.5 million (2020: nil) of PITA tax incurred by the Malaysian operations, offset by an Australian PRRT refund of US$1.4 million (2020: US$1.7 million paid) and corporate tax credit of US$0.8 million (2020: US$10.0 million expense).

Australian PRRT

Australian petroleum resource rent tax ("PRRT") is a cash based tax charged at the rate of 40% and is deductible from income tax. The current tax credit of US$1.4 million is associated with Stag operations, due to the utilisation of PRRT carried forward losses during the year. Montara is not anticipated to incur PRRT expense in the future, as it has unutilised PRRT carried forward credits of US$3.4 billion (2020: US$3.3 billion). Based on management's latest forecasts, the augmentation on historical accumulated PRRT net losses will more than offset PRRT that would otherwise arise on future PRRT taxable profits.

Malaysian PITA

Malaysian petroleum income tax ("PITA") is charged for each year of assessment derived from petroleum operations at the rate of 38%. The current tax charge represents the tax liability generated from the date of acquisition until the year end.

Deferred tax

The deferred tax movement during the year reflects timing differences for income tax, PITA and PRRT. The Group incurred a deferred tax charge of US$7.5 million in 2021, which consists of US$5.2 million for the recognition of net deferred tax liabilities on the Australian operations, US$3.4 million of deferred PRRT expense and US$1.1 million of deferred PITA credit. In 2020, the Group had a deferred tax credit of US$8.7 million, which consisted of US$4.0 million for the unwinding of deferred tax liabilities and US$4.7 million of deferred PRRT credit. The increase in deferred tax charge in 2021, compared to 2020, is explained by:

- Additional deferred tax liabilities recognised at the Australian operations, predominately arising from the additional capital expenditure spent at Montara in 2021, which created temporary taxable timing differences arising from the difference between the accounting base and the tax base of oil and gas properties, due to the immediate deductibility of the cost associated with the H6 drilling programme. The Group further recognised deferred tax liabilities arising from the insurance claim receivable of US$10.3 million on the well control claim for the Skua 11 well workovers. The insurance claim will be taxable in future following cash receipt;
- Deferred PRRT expense of US$3.4 million in 2021, arising from the reduction of deferred tax assets associated with Stag PRRT, following the utilisation of unutilised PRRT losses carried forward from 2020; and
- The Group incurred US$1.1 million of deferred PITA credit predominately arising from the recognition of deferred tax assets associated with the oil and gas properties based on the difference between the accounting depletion charge and the tax charge in 2021.

2021 Reconciliation of net cash

	USD'000	USD'000
Cash and cash equivalents, 31 December 2020	80,996	
Restricted cash, 31 December 2020	8,445	
Total cash and cash equivalent, 31 December 2020		**89,441**
Revenue	340,194	
Other operating income	6,030	
Production costs	(206,523)	
Staff costs	(24,117)	
General and administrative expenses	(18,962)	
Operating cash flows before movements in working capital		**96,622**
Movement in working capital		18,808
Net tax paid		(11,834)
Interest paid		(1,505)
Purchases of intangible exploration assets, oil and gas properties, and plant and equipment[1]		(55,920)
Net cash inflows from acquisition of PenMal Assets		9,219
Other investing activities		80
Financing activities		(27,046)
Total cash and cash equivalent, 31 December 2021		**117,865**

Net cash increased over the year due to the combination of higher realised prices and increased production due to the acquisition of the PenMal Assets, partially offset by the drilling of the H6 infill development well, spending on the Skua subsea workovers and non-routine repairs and maintenance.

The Group has been debt free following the final repayment of its reserves based loan in March 2021.

1 Total capital expenditure was US$56.0 million (2020: US$24.1 million), comprising total capital expenditure paid of US$55.9 million (2020: US$17.9 million), plus accrued capital expenditure of US$0.1 million (2020: US$6.1 million).

Non-IFRS measures

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

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

Operating costs per barrel of oil equivalent (Opex/boe)

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.

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 right-of-use assets involved in production, foreign exchange gains arising from foreign exchange forwards in respect of local currency operating expenditure, and excludes transportation costs, PenMal Asset supplementary payments, DD&A and short-term COVID-19 subsidies.

The adjusted production cost 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	2021	2020
Production costs (reported)	206,523	105,338
Adjustments		
Lease payments related to operating activity[1]	10,619	17,548
Underlift, overlift and crude inventories movement[2]	(9,680)	2,806
Workover costs[3]	(67,006)	(21,686)
Impact from FX derivatives apportioned to production costs[4]	-	(2,649)
Other income[5]	(4,512)	(3,634)
Non-recurring repair and maintenance[6]	(6,593)	(1,619)
Australian transportation costs	(1,231)	-
PenMal Assets supplementary payments[7]	(8,255)	-
Australian Government JobKeeper scheme	196	600
Adjusted production costs	**120,061**	**96,704**
Total production, (barrels of oil equivalent)	4,578,962	4,186,478
Operating costs per barrel of oil equivalent	**26.22**	**23.10**

1 Lease payments related to operating activities are lease payments considered to be operating costs in nature, including leased helicopters for transporting offshore crews, and the Dampier Spirit FSO rental fees prior to its lease termination in September 2020. 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 A portion of the net impact from foreign exchange hedging instruments was apportioned to production costs, based on the Group's actual local currency expenditure during the hedging period.

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

6 Non-recurring repair and maintenance costs in 2021 related to the Montara Swift North SCM change out and facility integrity baseline survey. The costs in 2020 related to costs associated with Cyclone Damien.

7 The supplementary payments are required under the terms of PSCs based on Jadestone's entitlement to profit from oil and gas. The payments are made to PETRONAS.

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 information 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, non-recurring expenses and exploration assets write-offs.

The calculation of adjusted EBITDAX is as follow:

USD'000	2021	2020
Revenue	340,194	217,938
Production cost	(206,523)	(105,338)
Staff cost	(25,068)	(21,903)
Impairment of assets	-	(50,455)
Other expenses	(26,181)	(26,918)
Other income, excluding interest income	7,602	26,119
Other financial gains	266	359
Unadjusted EBITDAX	**90,290**	**39,802**
Non-recurring		
Net loss/(gain) from oil price derivatives	4,633	(30,889)
Impairment of assets	-	50,455
Non-recurring opex[1]	53,096	8,270
Intangible exploration assets written off	5,260	-
Net litigation income	-	(3,005)
Rig contract deferred costs	-	3,000
Net loss/(gain) on contingent considerations	438	(359)
Gain from termination of FSO lease	-	(6,429)
Others[2]	4,231	1,737
	67,658	**22,780**
Adjusted EBITDAX	**157,948**	**62,582**

The Group EBITDAX reflects the strong cash operational performance of the assets with the creation of an additional US$158.0 million generated during 2021 before investing activities and non-recurring operating costs.

1 Includes one-off major maintenance/well intervention activities, in particular the workover campaigns at Montara Skua 10 & 11, Swift North SCM change out and facility integrity baseline survey in 2021. The 2020 one-off major maintenance/well intervention activities were comprised of Skua 10 and H3 workover campaigns, and other non-recurring production expenditures such as the repair and maintenance costs associated with weather downtime in 2020.

2 Includes Maari transition team costs, Australian Government JobKeeper scheme, business development and internal reorganisation costs, as well as Montara seismic acquisition costs associated with the non-licence area and gain on contingent consideration in 2020.

Outstanding debt

Total borrowings, as recorded in the Group's consolidated statement of financial position, represents the carrying amount of the Group's interest bearing financial indebtedness, measured at amortised cost pursuant to IFRS 9 *Financial Instruments*.

Outstanding debt is a non-IFRS measure which does not have a standardised meaning prescribed by IFRS. Management uses this measure to manage the capital structure, and make adjustments to it, based on the funds available to the Group. Outstanding debt is defined as long and short-term interest bearing debt, with effective interest method financing costs added back (i.e., excluded), and excluding derivatives.

As at 31 December 2021, the Group has no outstanding interest bearing financial indebtedness of any kind, following the final scheduled repayment of the RBL at the end of Q1 2021.

USD'000	2021	2020
Long-term borrowing	-	-
Short-term borrowing	-	7,296
Add back: effective interest method financing costs	-	1,021
Outstanding debt	**-**	**7,386**

Net cash

Net cash is a non-IFRS measure which does not have a standardised meaning prescribed by IFRS. Management uses this measure to analyse the financial strength of the Group. This measure is used to ensure capital is managed effectively in order to support ongoing operations, and to raise additional funds, if required.

USD'000	2021	2020
Outstanding debt	-	(7,386)
Cash and cash equivalents	117,865	81,996
Restricted cash	-	7,445
Net cash	**117,865**	**82,055**

Net cash is defined as the sum of cash and cash equivalents and restricted cash, less outstanding debt. Cash and cash equivalents in 2021 contain a restricted cash balance of US$0.4 million and US$0.5 million in relation to a deposit placed for bank guarantee with respect to the PenMal Assets and an Australian office building, respectively. In 2020, restricted cash included the RBL debt service reserve account balance of US$7.4 million but excluded US$1.0 million in respect of a cash collateralised bank guarantee with the Indonesian regulator with respect to a joint study agreement as the guarantee was removable and can then be used to fund the business. The Indonesian bank guarantee was released in Q3 2021 upon completion of the study.

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME
for the year ended 31 December 2021

	Notes	2021 USD'000	2020 USD'000
Revenue	5	340,194	217,938
Production costs	6	(206,523)	(105,338)
Depletion, depreciation and amortisation	7	(80,215)	(84,642)
Administrative staff costs	8	(25,068)	(21,903)
Other expenses	11	(26,181)	(26,918)
Impairment of assets	13	-	(50,455)
Other income	14	7,682	26,376
Finance costs	15	(9,075)	(12,655)
Other financial gains	16	266	359
Profit/(Loss) before tax		**1,080**	**(57,238)**
Income tax expense	17	(14,822)	(2,940)
Loss for the year		**(13,742)**	**(60,178)**
Loss per ordinary share			
Basic and diluted (US$)	18	(0.03)	(0.13)
Consolidated statement of comprehensive income			
Loss for the year		(13,742)	(60,178)
Other comprehensive income			
Items that may be reclassified subsequently to profit or loss:			
Gain on unrealised cash flow hedges	33	-	26,093
Hedging gain reclassified to profit or loss	33	-	(31,364)
		-	**(5,271)**
Tax income relating to components of other comprehensive income	17	-	1,583
Other comprehensive income		**-**	**(3,688)**
Total comprehensive income for the year		**(13,742)**	**(63,866)**

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

CONSOLIDATED STATEMENT OF FINANCIAL POSITION (Company Registration Number: 13152520) as at 31 December 2021

	Notes	2021 USD'000	2020 USD'000
Assets			
Non-current assets			
Intangible exploration assets	21	93,241	100,670
Oil and gas properties	22	353,592	317,676
Plant and equipment	23	8,963	1,652
Right-of-use assets	24	13,852	23,673
Other receivables and prepayment	28	48,500	4,404
Deferred tax assets	26	25,278	19,727
Total non-current assets		**543,426**	**467,802**
Current assets			
Inventories	27	23,299	45,361
Trade and other receivables	28	37,951	7,110
Tax recoverable		9,367	-
Restricted cash	29	-	8,445
Cash and cash equivalents	29	117,865	80,996
Total current assets		**188,482**	**141,912**
Total assets		**731,908**	**609,714**
Equity and liabilities			
Capital and reserves			
Share capital	30	559	466,979
Merger reserve	32	146,270	-
Share-based payments reserve	34	25,936	24,985
Accumulated losses		(31,692)	(331,322)
Total equity		**141,073**	**160,642**
Non-current liabilities			
Provisions	35	410,697	288,224
Lease liabilities	36	4,504	13,305
Tax liabilities		-	26,896
Deferred tax liabilities	26	67,097	58,229
Total non-current liabilities		**482,298**	**386,654**
Current liabilities			
Borrowings	37	-	7,296
Lease liabilities	36	11,161	12,478
Trade and other payables	39	69,090	32,192
Provisions	35	1,947	4,558
Derivative financial instruments	40	-	471
Tax liabilities		26,339	5,423
Total current liabilities		**108,537**	**62,418**
Total liabilities		**590,835**	**449,072**
Total equity and liabilities		**731,908**	**609,714**

The financial statements were approved by the Board of Directors and authorised for issue on 3 June 2022. They were signed on its behalf by:

A. Paul Blakeley
Director

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY for the year ended 31 December 2021

	Share capital USD'000	Merger reserve USD'000	Share-based payments reserve USD'000	Hedging reserves USD'000	Accumulated losses USD'000	Total USD'000
As at 1 January 2020	466,573	-	23,857	3,688	(268,651)	225,467
Loss for the year	-	-	-	-	(60,178)	(60,178)
Other comprehensive income for the year	-	-	-	(3,688)	-	(3,688)
Total comprehensive income for the year	**-**	**-**	**-**	**(3,688)**	**(60,178)**	**(63,866)**
Dividend paid (Note 31)	-	-	-	-	(2,493)	(2,493)
Share-based compensation (Note 8)	-	-	1,128	-	-	1,128
Shares issued (Note 30)	406	-	-	-	-	406
Total transactions with owners, recognised directly in equity	**406**	**-**	**1,128**	**-**	**(2,493)**	**(959)**
As at 31 December 2020	**466,979**	**-**	**24,985**	**-**	**(331,322)**	**160,642**
Loss for the year, representing total comprehensive income for the year	-	-	-	-	(13,742)	(13,742)
Capital reduction (Note 30)	(467,387)	146,270	-	-	321,117	-
Dividend paid (Note 31)	-	-	-	-	(7,745)	(7,745)
Share-based compensation (Note 8)	-	-	951	-	-	951
Shares issued (Note 30)	967	-	-	-	-	967
Total transactions with owners, recognised directly in equity	**(466,420)**	**146,270**	**951**	**-**	**313,372**	**(5,827)**
As at 31 December 2021	**559**	**146,270**	**25,936**	**-**	**(31,692)**	**141,073**

CONSOLIDATED STATEMENT OF CASH FLOWS
for the year ended 31 December 2021

	Notes	2021 USD'000	2020 USD'000
Operating activities			
Profit/(Loss) before tax		1,080	(57,238)
Adjustments for:			
Depletion, depreciation and amortisation	7	69,024	68,414
Depreciation of right-of-use assets	7	11,191	16,228
Other finance costs	15	8,487	10,289
Assets written off	11	5,332	173
Allowance for slow moving inventories	11	2,624	143
Unrealised foreign exchange (gain)/loss	11 / 14	(1,838)	1,495
Share-based payments	8	951	1,128
(Reversal of)/Fair value loss on oil derivatives	11	(471)	471
Change in fair value of contingent payments	15 / 16	438	(359)
Accretion income on non-current VAT receivables	16	(266)	-
Interest expense	15	150	2,366
Interest income	14	(80)	(257)
Impairment of intangible exploration assets	13	-	50,455
Loss on ineffective hedge recycled to profit or loss	11	-	4
Change in Stag FSO provision	14	-	(5,047)
Gain from termination of right-of-use asset	14	-	(1,382)
Operating cash flows before movements in working capital		**96,622**	**86,883**
(Increase)/Decrease in trade and other receivables		(11,975)	35,560
Decrease/(Increase) in inventories		9,152	(14,071)
Increase in trade and other payables		21,631	3,736
Cash generated from operations		**115,430**	**112,108**
Interest paid		(1,505)	(1,542)
Tax refunded		3,652	-
Tax paid		(15,486)	(25,969)
Net cash generated from operating activities		**102,091**	**84,597**
Investing activities			
Cash received from acquisition of Peninsular Malaysia assets	19	29,252	-
Cash paid for acquisition of Peninsular Malaysia assets	19	(20,033)	-
Net cash outflows on acquisition of Lemang PSC	20	-	(11,959)
Payment for oil and gas properties	22	(51,380)	(4,732)
Payment for plant and equipment	23	(682)	(473)
Payment for intangible exploration assets	21	(3,858)	(14,253)
Transfer from debt service reserve account	29	8,445	5,040
Interest received	14	80	257
Net cash used in investing activities		**(38,176)**	**(26,120)**
Financing activities			
Proceeds from issuance of shares	30	967	406
(Placement)/Release of deposit for bank guarantee	29	-	10,000
Dividend paid	31	(7,745)	(2,493)
Repayment of borrowings	38	(7,296)	(42,766)
Repayment of lease liabilities	38	(12,972)	(18,562)
Net cash used in financing activities		**(27,046)**	**(53,415)**
Net increase in cash and cash equivalents		**36,869**	**5,062**
Cash and cash equivalents at beginning of the year		80,996	75,934
Cash and cash equivalents at end of the year	29	**117,865**	**80,996**

SIGNIFICANT ACCOUNTING POLICIES AND EXPLANATION NOTES TO THE FINANCIAL STATEMENTS for the year ended 31 December 2021

1 CORPORATE INFORMATION

Jadestone Energy plc (the "Company" or "Jadestone") is an oil and gas company incorporated in the United Kingdom and registered in England and Wales. The Company was incorporated on 22 January 2021, company registration number 13152520. The Company became the ultimate parent company of the Group on completion of an internal reorganisation (Note 2) on 23 April 2021. Prior to the internal reorganisation, Jadestone Energy Inc., an oil and gas company incorporated in Canada, had been the ultimate parent company of all Jadestone subsidiaries (the "Group"). These consolidated financial statements have been prepared for the Jadestone Energy Group and reflect the full financial year ended 31 December 2021 in respect of the ultimate parent company in accordance with IFRS, (see Note 3).

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 and Indonesia. The Group's producing assets are in the Vulcan (Montara) and Carnarvon (Stag) basins, located in shallow water offshore of Western Australia, and in the East Piatu, East Belumut, West Belumut and Chermingat fields, located in shallow water in offshore Peninsular Malaysia.

The Company's head office is located at 3 Anson Road, #13-01 Springleaf Tower, Singapore 079909. The registered office of the Company is Suite 1, 3rd Floor, 11 - 12 St James's Square, London SW1Y 4LB.

The financial information, comprising of the consolidated statement of profit or loss and other comprehensive income, consolidated statement of financial position, consolidated statement of changes in equity, consolidated statement of cash flows and related notes, has been taken from the consolidated financial statements of Jadestone Energy plc ("Company") for the year ended 31 December 2021, which were approved by the Board of Directors on 3 June 2022. The financial information does not constitute statutory accounts within the meaning of sections 435(1) and (2) of the Companies Act 2006 or contain sufficient information to comply with the disclosure requirements of International Financial Reporting Standards ("IFRS").

An unqualified report on the consolidated financial statements for the year ended 31 December 2021 has been given by the auditors, Deloitte Ireland LLP. It did not include reference to any matters to which the auditors drew attention by way of emphasis without qualifying their report and did not contain any statement under section 498 (2) or (3) of the Companies Act 2006. The consolidated financial statements will be filed with the Registrar of Companies, subject to their approval by the Company's shareholders at the Company's Annual General Meeting on 30 June 2022.

2 SIGNIFICANT EVENTS DURING THE YEAR

Internal reorganisation

The Company completed an internal reorganisation on 23 April 2021, with Jadestone Energy plc becoming the ultimate holding company of the Jadestone group of companies. The shares of Jadestone Energy Inc., the former ultimate holding company, were replaced on a one-for-one basis with shares of Jadestone Energy plc. Following the completion of the internal reorganisation, the shares of Jadestone Energy plc were admitted to AIM for trading on 26 April 2021 (shares of Jadestone Energy Inc. ceased trading on 23 April 2021).

The internal reorganisation did not result in a change in control in the ultimate holding company nor the ultimate shareholding or management of any Jadestone group company.

The reorganisation was undertaken for several reasons. It is expected to reduce regulatory compliance burdens and raise the Company's profile and status amongst UK and European investors who are unable to invest in non-UK domiciled companies. It is also expected to facilitate incremental access to equity from international capital markets, and to allow Jadestone to further optimise its tax structure.

Acquisition of SapuraOMV Peninsular Malaysia assets

On 30 April 2021, the Group executed a sale and purchase agreement with SapuraOMV Upstream Sdn Bhd ("SapuraOMV") to acquire SapuraOMV's Peninsular Malaysia assets (the "PenMal Assets"), for a total cash consideration of US$20.0 million, which included a headline price of US$9.0 million plus further working capital adjustments of US$11.0 million. There are two separate potential contingent payments which occur if the average Dated Brent is above US$65/bbl in 2021 and above US$70/bbl in 2022. The Group paid the first contingent payment of US$3.0 million in January 2022. The acquisition completed on 1 August 2021, following the satisfaction of all conditions precedent to closing the acquisition.

The economic effective date of the acquisition was 1 January 2021, meaning the Group is entitled to all net cash generated from the PenMal Assets from 1 January 2021 to 31 July 2021, resulting in a net cash receipt at closing of US$9.2 million.

The PenMal Assets comprise four licences, two of which are operated by the Group, a 70% operated interest in the PM329 PSC, containing the East Piatu field, and a 60% operated interest in the PM323 PSC, which contains the East Belumut, West Belumut and Chermingat fields. The other two licences comprise 50% non-operated working interests in the PM318 and Abu, Abu Kecil, Bubu, North Lukut, and Penara oilfields ("AAKBNLP") PSCs.

Oil price commodity contracts

On 16 February 2021, the Group entered into commodity swap contracts to hedge 31% of its planned production volumes from April to June 2021, to provide downside oil price protection in the lead-up period to the Group's 2021 offshore Australia capital programme. The average swap price, referenced to Dated Brent, was set at US$61.40/bbl.

3 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of preparation

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

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

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

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

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Group can access at the measurement date;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

Common control transaction

As disclosed in Note 2, the Company has completed an internal reorganisation, with the shares of Jadestone Energy Inc. having been replaced on a one-for-one basis with shares of Jadestone Energy plc. Accordingly, the shares of Jadestone Energy plc were admitted to AIM for trading on 26 April 2021. There is no change in control in the ultimate holding company of the Group, nor the ultimate shareholding or management of any Jadestone group company, arising from the completion of the internal reorganisation.

IFRS 3 *Business Combinations* does not prescribe the presentation and disclosure requirements under a common control transaction. The Group has chosen to issue these consolidated financial statements under the name of Jadestone Energy plc, as if they are a continuation of the financial statements of Jadestone Energy Inc. and Jadestone Energy plc had been in existence throughout the reported financial year.

The following have been reflected in these consolidated financial statements in relation to the common control transaction:

a) The asset and liabilities of Jadestone Energy plc and Jadestone Energy Inc. ("JEI") group have been recognised at their book values immediately prior to the internal reorganisation;
b) The pre-internal reorganisation accumulated losses recognised in these consolidated financial statements are those of JEI Group;
c) The amount recognised as issued equity instruments in these consolidated financial statements is the issued and paid-up share capital of JEI immediately before the internal reorganisation. The comparative share capital is that of the Company as if the Company headed the Group for the comparative period;
d) The equity structure appearing in these consolidated financial statements (i.e., the number and type of equity instruments issued) reflects the equity structure of the Company;
e) A merger reserve account was created to account the difference between the carrying value and the nominal value of the shares of the Company; and
f) The comparative information presented in these consolidated financial statements is that of JEI Group with the exception of the composition of the equity items which reflect that of the Company as if the Company had existed for the comparative period.

Going concern

The Directors are required to consider the availability of resources to meet the Group's liabilities for the foreseeable future.

As at 31 December 2021, the Group has a total cash and cash equivalents of US$117.9 million, and the Group managed to keep the cash levels within the range of US$90.0 to US$105.0 million between January to April 2022, after the settlements of trade related expenditure and US$3.0 million contingent payment paid to SapuraOMV arising from the acquisition of PenMal Assets (Notes 19 and 38). The average Dated Brent crude prices for the first four months in 2022 was US$102.73/bbl, hence the Group was able to generate material cash inflows from the liftings in Australia and Malaysia from the beginning of 2022 up to date.

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. Downside price and other risking scenarios are considered, such as potential delay in the development of Lemang asset, unfavourable foreign exchanges and higher than expected inflation rates. In addition to commodity sales prices, the Group is also potentially exposed to potential production interruptions such as weather downtime and planned and unplanned shutdowns for workovers and repair and maintenance activities. All these factors have been considered in the Group's near and longer term cash projections. For the purposes of the Group's going concern assessment, we have reviewed cash projections for the period from 1 April 2022 to 30 June 2023, the 'going concern period'.

The Group is debt-free, following the final repayment of its Australian reserve based lending facility in Q1 2021. All of its operational and capital commitments (Note 43) can be funded from the existing cash resources.

Having taken into consideration the above factors, the Directors have reasonable expectation that the Group has adequate resources to continue in operational existence for the going concern period. Accordingly, they adopted the going concern basis in preparing these financial statements.

Adoption of new and revised standards

New and amended IFRS standards that are effective for the current year

In the current year, the Group adopted the following amendment that is effective from the beginning of the year and is relevant to its operations. The adoption of this amendment has not resulted in changes to the Group's accounting policies.

Amendments to IFRS 16	COVID-19-Related Rent Concessions Beyond 30 June 2021

New and revised IFRSs in issue but not yet effective

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

Amendments to IAS [1]	Classification of Liabilities as Current or Non-current
Amendments to IAS 1 and Practice Statement 2[1]	Making Materiality Judgements – Disclosure of Accounting Policies
Amendments to IAS 8[1]	Definition of Accounting Estimates
Amendments to IAS 12[1]	Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction
Amendments to IFRS 16[2]	Property, Plant and Equipment – Proceeds before Intended Use
Amendments to IFRS 37[2]	Onerous Contracts – Cost of Fulfilling a Contract
Amendments to IFRS 3[2]	Reference to Conceptual Framework
Amendments to IFRSs[2]	Annual Improvements to IFRS Standards 2018 – 2020

The Group is currently performing an assessment of the impact of these amendments but does not expect a material impact on the financial statements of the Group in future periods.

1 Effective from 1 January 2023.
2 Effective from 1 January 2022.

Basis of consolidation

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

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

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

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

Profit or loss and each component of other comprehensive income are attributed to the owners of the Company. Total comprehensive income of subsidiaries is attributed to the owners of the Company and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance.

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

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

Business combinations

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

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

- Deferred tax assets or liabilities, and liabilities or assets related to employee benefit arrangements are recognised and measured in accordance with IAS 12 *Income Taxes* and IAS 19 *Employee Benefits* respectively;
- Liabilities or equity instruments related to share-based payment transactions of the acquiree, or the replacement of an acquiree's share-based payment awards transactions with share-based payment awards transactions of the acquirer, in accordance with the method in IFRS 2 *Share-based Payment* at the acquisition date; and
- Assets, or disposal groups, that are classified as held for sale in accordance with IFRS 5 *Non-Current Assets Held for Sale and Discontinued Operations* are measured in accordance with that Standard.

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

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

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

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

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

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

Accounting for transaction that is not a business combination

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

- Identifies and recognises the individual identifiable assets acquired (including those assets that meet the definition of, and recognition criteria for, intangible assets in IAS 38) and liabilities assumed; and
- Allocates the cost of acquiring the group of assets and liabilities to the individual identifiable assets and liabilities on the basis of their relative fair values at the date of purchase.

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

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

Foreign currency transactions

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

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

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

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

Joint operations

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

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

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

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

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

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

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

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

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

Pre-licence award costs

Costs incurred prior to the effective award of oil and gas licences, concessions and other exploration rights, are expensed in profit or loss.

Exploration and evaluation costs

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

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

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

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

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

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

Oil and gas properties

Producing assets

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

Depletion and amortisation expense

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

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

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

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

Asset restoration obligations

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

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

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

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

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

Borrowing Costs

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

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

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

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

Government grants

Government grants are not recognised until there is reasonable assurance that the Group will comply with the conditions attached to them and that the grants will be received.

The government grants received in 2020 related to the Australian Government’s JobKeeper Scheme, as part of the Australian Government initiative to provide immediate financial support as a result of the COVID-19 pandemic, and applied to certain of the Group’s Australian offshore and onshore personnel. There are no future related costs in respect of these grants, which were received solely as compensation for costs incurred during the year. There are no unfulfilled conditions or other contingencies in relation to the grants.

Government grants are recognised in profit or loss on a systematic basis over the periods in which the Group recognises as expenses the related costs for which the grants are intended to compensate.

Government grants are presented on a net basis in profit or loss, where grant income is offset against the related costs, in either “production costs” (Note 6) or “administrative staff costs” (Note 8).

Plant and equipment

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

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

- Computer equipment: 3 years; and
- Fixtures and equipment: 3 years.

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

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

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

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

Impairment of oil and gas properties, plant and equipment, right-of-use assets and intangible assets excluding goodwill

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

Intangible assets with indefinite useful lives and intangible assets not yet available for use, are tested for impairment annually, and whenever there is an indication that the asset may be impaired.

Recoverable amount is the higher of fair value less costs of disposal ("FVLCOD") and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which estimates of future cash flows have not been adjusted. FVLCOD will be assessed on a discounted cash flow basis where there is no readily available market price for the asset or where there are no recent market transactions. Assumptions relating to forecast capital expenditures that enhance the productive capacity can be included in the discounted cash flows model, but only to the extent that a typical market participant would take a consistent view. The post-tax discounted cash flows are compared against the carrying amount of the asset on an after-tax basis; that is, after deducting deferred tax liabilities relating to the asset or group of assets.

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

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

Inventories

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

- Petroleum products, comprising primarily of extracted crude oil stored in tanks, pipeline systems and aboard vessels, and natural gas, are valued using weighted average costing, inclusive of depletion expense; and
- Materials, which include drilling and maintenance stocks, are valued at the weighted average cost of acquisition.

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

Provision for slow moving materials and spares are recognised in the "other expenses" (Note 11) line item in profit or loss as they are non-trade in nature.

Financial Instruments

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

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

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

Financial assets

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

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

Classification of financial assets

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

- The financial asset is held within a business model whose objective is to hold financial assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

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

- The financial asset is held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

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

Amortised cost and effective interest method

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

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

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

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

Interest income is recognised in profit or loss and is included in "other income" (Note 14) line item.

Impairment of financial assets

The Group's financial assets that are subject to the expected credit loss model comprise trade and other receivables. While cash and bank balances are also subject to the impairment requirements of IFRS 9 *Financial Instruments*, the expected credit loss allowances are not expected to be significant.

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

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

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

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

Significant increase in credit risk

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

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

- An actual or expected significant deterioration in the financial instrument's external (if available), or internal credit rating;
- Significant deterioration in external market indicators of credit risk for a particular financial instrument, e.g., a significant increase in the credit spread, the credit default swap prices for the debtor, or the length of time or the extent to which the fair value of a financial asset has been less than its amortised cost;
- Existing or forecast adverse changes in business, financial or economic conditions that are expected to cause a significant decrease in the debtor's ability to meet its debt obligations;
- An actual or expected significant deterioration in the operating results of the debtor;
- Significant increases in credit risk on other financial instruments of the same debtor; and
- An actual or expected significant adverse change in the regulatory, economic, or technological environment of the debtor that results in a significant decrease in the debtor's ability to meet its debt obligations.

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

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

Definition of default

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

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

Credit-impaired financial assets

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

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

Write-off policy

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

Measurement and recognition of expected credit losses

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

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

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

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

Derecognition of financial assets

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

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

Financial liabilities

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

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

Financial liabilities at FVTPL

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

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

- Such designation eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise; or
- The financial liability forms part of a group of financial assets or financial liabilities or both, which is managed and its performance is evaluated on a fair value basis, in accordance with the Group's documented risk management or investment strategy, and information about the grouping is provided internally on that basis; or
- It forms part of a contract containing one or more embedded derivatives, and IFRS 9 permits the entire combined contract to be designated as at FVTPL.

Financial liabilities classified as at FVTPL are measured at fair value, with any gains or losses arising on changes in fair value recognised in profit or loss to the extent that they are not part of a designated hedging relationship (see hedge accounting policy). The net gain or loss recognised in profit or loss incorporates any interest paid on the financial liability and is included in either "other financial gains" (Note 16) or "finance costs" (Note 15) line item in profit or loss.

Financial liabilities measured subsequently at amortised cost

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

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

Derecognition of financial liabilities

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

Equity instruments

Ordinary shares issued by the Company are classified as equity and recorded at the fair value of the proceeds received.

Derivative financial instruments

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

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

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

Hedge accounting

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

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

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Group actually hedges and the quantity of the hedging instrument that the Group actually uses to hedge that quantity of hedged item.

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

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

Note 40 sets out details of the fair values of the derivative instruments used for hedging purposes.

Movements in the hedging reserve in equity are detailed in Note 33.

Cash flow hedges

The effective portion of changes in the fair value of derivatives and other qualifying hedging instruments that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated under the heading of cash flow hedging reserve, limited to the cumulative change in fair value of the hedged item from inception of the hedge. The gain or loss relating to the ineffective portion is recognised immediately in profit or loss in either "other financial gains" (Note 16) or "finance costs" (Note 15) line item.

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

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

Fair value estimation of financial assets and liabilities

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

Share-based payments

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

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

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

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

Leases

The Group as lessee

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

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

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

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

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

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

- The lease term has changed or there is a significant event or change in circumstances resulting in a change in the assessment of exercise of a purchase option, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate;
- The lease payments change due to changes in an index or rate or a change in expected payment under a guaranteed residual value, in which case the lease liability is remeasured by discounting the revised lease payments using an unchanged discount rate (unless the lease payments change is due to a change in a floating interest rate, in which case a revised discount rate is used); or
- A lease contract is modified and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured based on the lease term of the modified lease by discounting the revised lease payments using a revised discount rate at the effective date of the modification.

During the year, the Group did not make any such adjustments. In 2020, the Group had revalued certain lease liabilities to nil following the termination of those leases.

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

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

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

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

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

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

Provisions

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

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows, and where the effect of the time value of money is material. The provisions held by the Group are asset restoration obligations, contingent payments, employee benefits and incentive scheme, as set out in Note 35.

Retirement benefit obligations

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

Revenue

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

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

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

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

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

Under/Overlift

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

An overlift liability is recorded as a current liability in the statement of financial position at the prevailing market price, to represent a provision for production costs attributable to the volumes sold in excess of entitlement. An underlift asset is recorded as a current receivable in the statement of financial position at the prevailing market price, to represent a right to additional inventory based on its entitlement. Movements during an accounting period are adjusted through production costs such that gross profit is recognised on an entitlement basis.

Income tax

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

Current tax

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

Petroleum resource rent tax (PRRT)

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

PRRT is calculated at the rate of 40% of sales revenues less certain permitted deductions and is tax deductible for income tax purposes. In calculating the deferred tax in relation to PRRT, the PRRT rate is combined with Australian corporate tax rate of 30% to derive a combined effective tax rate of 28%.

Malaysia Petroleum Income Tax (PITA)

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

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

Deferred tax

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

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

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

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

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

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

Current and deferred tax for the year

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

Other taxes

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

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

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

Cash and bank balances

Cash and bank balances comprise cash in hand and at bank, and other short-term deposits held by the Group with maturities of less than three months. Restricted cash in the current year is presented as cash and cash equivalents in the consolidated statement of financial position and disclosed in Note 29.

4 CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

Climate change and energy transition

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

The Group has assessed the potential impacts of climate change and the transition to a lower carbon economy in preparing the consolidated financial statements, including the Group's current assumptions relating to demand for oil and gas and their impact on the Group's long-term price assumptions, and also taking into consideration of the forecasted long-term prices and demand for oil and gas under the Paris aligned scenarios. See the key estimates on pages 142 and 143 of the 2021 Annual Report for reserves estimates and impairment of oil and gas properties.

While the pace of transition to a lower carbon economy is uncertain, oil and gas demand is expected to remain a key element of the energy mix in the foreseeable future based on stated policies, commitments and announced pledges to reduce emissions.

Therefore, given the useful lives of the Group's current portfolio of oil and gas assets of up to 2040, management does not expect the potential decline on oil prices as a result of climate change and the transition to a lower carbon economy will have a material adverse change to the operating cash flows of the Group during the lives of those assets and thus the carrying amounts of the Group's assets and liabilities will not be significantly impacted.

Management will continue to review price assumptions as the energy transition progresses and will take into consideration in the future impairment assessments.

Critical accounting judgments

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

- **Acquisitions, divestitures and/or assignment of interests**

  The Group accounts for acquisitions and divestitures by considering if the acquired or transferred interest relates to that of an asset, or of a business as defined in IFRS 3 Business Combinations. Accordingly, the Group considers if there is the existence of business elements (e.g., inputs and substantive processes), or a group of assets that includes inputs and substantial processes that together significantly contribute to the ability to create outputs and providing a return to investors or other economic benefits. The justifications for this assessment on both acquisition of PenMal Assets and Lemang PSC have been set out in Notes 19 and Note 20, respectively.

Key sources of estimation uncertainty

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

a) Deferred taxes

The Group recognises the net future economic benefit of deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future and the carry forward of unutilised tax credits and unutilised tax losses can be utilised accordingly. Assessing the recoverability of deferred income tax, PRRT and PITA assets require the Group to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Group to realise the net deferred tax assets as recorded in the statement of financial position, could be impacted.

The carrying amount of the Group's deferred tax assets are disclosed in Note 26 to the financial statements.

Sensitivity analysis

Sensitivities have been run on the oil price assumption, with a 10% change being considered a reasonable possible change for the purposes of sensitivity analysis. A 10% decrease/increase in oil price would not result in a change in the deferred tax asset recognised by the Group due to the unrecognised deferred tax assets being associated with the unwinding of provision of asset retirement obligations in the future during the decommissioning period. The Group is not expected to be in taxable profit position during the decommissioning period to enable it to utilise the unrecognised deferred tax assets at year end.

b) Reserves estimates

The Group's estimated reserves are management assessments, and take into consideration audits performed by an independent third party, which includes various assumptions, interpretations and assessments. These include assumptions regarding commodity prices, exchange rates, future production, transportation costs, and interpretations of geological and geophysical models to make assessments of the quality of reservoirs and the anticipated recoveries. Changes in reported reserves can impact asset carrying amounts, the provision for restoration and the recognition of deferred tax assets, due to changes in expected future cash flows. Reserves are integral to the amount of depreciation, depletion and amortisation charged to the statement of profit or loss and other comprehensive income, and the calculation of inventory. Based on the analysis performed, management does not expect a five percent increase/decrease in the reserve estimates would significantly impact the carrying amounts of the assets and liabilities of the Group at year end.

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

The Group undertakes a regular review of asset carrying amounts to determine whether there is any indication of impairment. In the impairment assessment of intangible exploration assets, the Group takes into consideration the technical feasibility and commercial viability of extracting a mineral resource and whether there is any adverse information that will affect the final investment decision.

For oil and gas properties, management assesses recoverable amounts using the FVLCOD approach. The post-tax estimated future cash flows are prepared based on estimated reserves, future production profiles, future hydrocarbon price assumptions and costs. The future hydrocarbon price assumptions used are highly judgemental and may be subject to increased uncertainty given climate change and the global energy transition. Management further takes into consideration the impact of climate change on estimated future commodity prices with the application of the Paris aligned price assumptions.

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

Sensitivity analysis

Management assessed the impact of a change in cash flows in impairment testing arising from a 10% reduction in price assumptions used at year end, sourced from independent third party, ERCE. The forecasted price assumptions are US$75/bbl in 2022, US$70/bbl in 2023 and US$66/bbl from 2024 onwards. Based on the analysis performed, management concluded that a price reduction in isolation under the various scenarios would not impact the carrying amount of the Group's oil and gas properties. Management also assessed the impact of a change in cash flows in impairment testing arising from the application of the various Paris aligned price assumptions, being Announced Pledges Scenario (II), Net Zero Emissions by 2050 Scenario (central) and Net Zero Emissions by 2050 Scenario (APD) as disclosed on pages 35 to 38 of the 2021 Annual Report. The oil price under the various Paris aligned price assumptions are as follow:

	2022 US$/bbl	2023 US$/bbl	2024 US$/bbl	2025 US$/bbl	2026 US$/bbl	2027 onwards US$/bbl
Announced Pledges Scenario (II)	71.7	70.9	64.9	59.9	56.3	63.1
Net Zero Emissions by 2050 Scenario (central)	67.8	65.3	57.5	50.7	46.5	42.9
Net Zero Emissions by 2050 Scenario (APD)	71.3	70.4	64.2	58.9	54.5	51.7

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

Management also tested the impact of a one percent change in the discount rate used of 10% for impairment testing of oil and gas properties, and concluded that a five percent increase/decrease in the discount rate will not result in impairment as the net present value of either outcome is above the carrying amount of the Group's oil and gas properties at year end.

d) Asset restoration obligations

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

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

The carrying amounts of the Group's asset restoration obligations is disclosed in Note 35 to the financial statements.

Sensitivity analysis

Sensitivities have been run on the discount rate assumption, with a one percentage change being considered a reasonable possible change for the purposes of sensitivity analysis. A one percentage reduction in discount rate would increase the liability by US$41.9 million and a one percentage increase in discount rate would decrease the liability by US$36.4 million. A 10% increase in current estimated costs would increase the liability by US$35.8 million and a 10% decrease in current estimated costs would decrease the liability by US$35.3 million. A one year deferral to the estimated decommissioning date would decrease the liability by US$1.1 million and an acceleration of one year to the estimated decommissioning date would increase the liability by US$0.2 million.

5 REVENUE

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

In line with the revenue accounting policies set out in Note 3, all revenue is recognised at a point in time.

	2021 USD'000	2020 USD'000
Liquids revenue	339,210	186,572
Hedging income	-	31,366
	339,210	**217,938**
Gas revenue	984	-
	340,194	**217,938**

The Group entered into Australian commodity swap contracts hedging approximately 30% of its planned production for the period January to June 2021. The commodity swap contracts were measured at FVTPL, as opposed to hedge accounting, in part because the swap contracts cover a short time span. The swap contracts incurred a loss of US$4.6 million during the year which is recorded as other expense (Note 11).

The hedging income in 2020 arose from the Group's capped swap contracts from October 2018 to September 2020, by hedging 50% of its planned production volumes during the contracts' duration.

6 PRODUCTION COSTS

	2021 USD'000	2020 USD'000
Operating costs	61,630	45,155
Workovers	67,006	21,686
Logistics	20,212	18,853
Repairs and maintenance	45,186	22,450
Tariffs and transportation costs	2,809	-
Underlift, overlift and crude inventories movement	9,680	(2,806)
	206,523	**105,338**

Operating costs predominately consists of offshore manpower costs of US$26.8 million (2020: US$20.7 million), chemical, services, supplies and others of US$20.3 million (2020: US$20.3 million), Malaysian supplementary payments of US$8.3 million (2020: nil), insurance of US$2.7 million (2020: US$3.0 million) and non-operated assets production costs of US$1.2 million (2020: nil). The Malaysian supplementary payments are required under the terms of PSCs based on the Group's entitlement to profit from oil and gas. It is payable at 70% of the excess revenue over the base price of the sale of oil as set out under the terms of PSCs. The payments are made to PETRONAS.

Workovers in 2021 included the Montara subsea workovers for the Skua 10 and Skua 11 wells of US$47.2 million, net of insurance claim receivable of US$10.3 million on the well control claim for the Skua 11 well workovers.

Repairs and maintenance in 2021 include a once-in-every-three-year subsea flowline inspection and Swift North subsea control module change out at Montara and a once-in-five-year changeout of the under-buoy hose at Stag.

The operating costs in 2020 were net of US$0.6 million received during the year from the Australian Government's JobKeeper scheme in respect of COVID-19 grants supporting certain of the Group's Australian offshore workforce.

7 DEPLETION, DEPRECIATION AND AMORTISATION ("DD&A")

	2021 USD'000	2020 USD'000
Depletion and amortisation (Note 22):	62,586	68,005
Depreciation of:		
Plant and equipment (Note 23)	508	601
Right-of-use assets (Note 24)	11,191	16,228
Crude inventories movement	5,930	(192)
	80,215	**84,642**

The depreciation of right-of-use assets in 2021 includes US$1.5 million (2020: nil) associated with the Skua 10 and 11 workovers.

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

Crude inventories movement represents the year on year differential of the Group's on hand closing inventory. The depletion charge is calculated based on units of production and adjusted based on the net movement of crude inventories at year end against beginning of the year. There were 274,103 bbls at the end of 2021 compared to 601,999 bbls at the end of 2020 reflecting an additional depletion charge of US$5.9 million.

8 ADMINISTRATIVE STAFF COSTS

	2021 USD'000	2020 USD'000
Wages, salaries and fees	21,066	17,520
Staff benefits in kind	3,051	3,255
Share-based compensation	951	1,128
	25,068	**21,903**

The compensation of key management personnel is included in the above and disclosed separately in Note 45.

Wages, salaries and fees in 2020 were net of US$0.5 million received during the year from the Australian Government's JobKeeper scheme in respect of certain of the Group's Australian onshore personnel.

9 STAFF NUMBERS AND COSTS

The average number of employees employed by the Group during the year was 278 (2020: 210), consisting of 153 onshore employees (2020: 117) and 125 offshore employees (2020: 93). Staff costs are split between production costs (Note 6) for offshore personnel and administrative staff costs (Note 8) for onshore personnel.

Their aggregate remuneration comprised:

	2021 USD'000	2020 USD'000
Wages, salaries and fees	39,158	35,434
Social security costs	186	206
Defined contribution pension costs	3,177	2,594
Share-based compensation	951	1,128
	43,472	**39,362**
Contractors and consultants costs	8,363	3,191
	51,835	**42,553**

10 DIRECTORS' REMUNERATION AND TRANSACTIONS

	2021 USD'000	2020 USD'000
Directors' remuneration		
Salaries, fees, bonuses and benefits in kind	3,093	2,823
Gains on exercise of options	1,259	-
Amounts receivable under long term incentive plans	278	493
Money purchase pension contributions	96	72
	4,726	**3,388**
Remuneration of the highest paid director:		
Salaries, fees, bonuses and benefits in kind	1,516	1,472
Gains on exercise of options	481	-
Amounts receivable under long term incentive plans	302	282
Money purchase pension contributions	63	44
	2,362	**1,798**

	Number	Number
The number of directors who:		
Are members of a defined benefit pension scheme	-	-
Are members of a money purchase pension scheme	2	2
Exercised options over shares in the Company	2	-
Had awards receivable in the form of shares under a long-term incentive scheme	2	8

In 2021, the Non-Executive Directors were not granted any options/shares under the Company's long term incentive plans, compared to 2020 when all Directors were granted share options.

11 OTHER EXPENSES

	2021 USD'000	2020 USD'000
Corporate costs	11,487	16,642
Assets written off	5,332	173
Loss on valuation of oil derivatives	4,633	475
Provision for slow moving inventories	2,624	143
Net foreign exchange loss	950	2,623
Rig contract deferral costs	-	3,000
Exploration expenses	-	972
Other expenses	1,155	2,890
	26,181	**26,918**

Corporate costs in 2021 includes business development costs of US$3.2 million, professional fees in relation to internal reorganisation of US$1.1 million and project transition costs of US$0.9 million (2020: US$1.0 million). Corporate costs in 2020 included US$9.1 million of litigation costs incurred in relation to the SC56 and Block 05-1 PSC.

Loss on valuation of oil derivatives arose from the Australian commodity swap contracts entered for the period January to June 2021.

Assets written off in 2021 includes the written off of intangible exploration assets of US$5.3 million previously capitalised as they are not expected to generate future economic benefits.

For the purpose of the consolidated statement of cash flows, net foreign exchange loss in 2020 included net unrealised loss of US$1.5 million.

Rig contract deferral costs in 2020 of US$3.0 million arose from the decision to defer the Australian 2020 drilling campaign in response to the impact of COVID-19.

12 AUDITORS' REMUNERATION

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

	2021 USD'000	2020 USD'000
Fees payable to the Company's auditor for the audit of the parent company and Group's consolidated financial statements	383	208
Audit fees of the subsidiaries	412	174
	795	**382**

No fees were paid to the Group's auditors for non-audit services for either the Group or the Company in 2020 or 2021.

The increase in fees relates mainly to the internal reorganisation in April 2021 which required the Group auditors to be United Kingdom rather than Singapore based.

13 IMPAIRMENT OF ASSETS

	2021 USD'000	2020 USD'000
Impairment of intangible exploration assets (Note 21)	-	50,455

The impairment expense of US$50.5 million in 2020 related to management's decision to voluntarily relinquish SC56, a deepwater new basin entry exploration block acquired by the previous management of the Group. The effective date of relinquishment was 21 December 2020. During the year, the Group paid an exit fee of US$1.5 million to the Philippines Department of Energy and formally exited the block. A provision was made in relation to the exit fee in 2020 which reversed out in 2021 after the payment was made.

14 OTHER INCOME

	2021 USD'000	2020 USD'000
Net foreign exchange gain	2,525	48
Interest income	80	257
Litigation income	-	11,075
Reversal of Stag FSO provision	-	5,047
Fair value gain on foreign exchange derivatives	-	3,784
Gain from termination of right-of-use asset	-	1,382
Other income	5,077	4,783
	7,682	**26,376**

Other income includes rental income from a helicopter rental contract (a right-of-use asset) to a third party of US$4.5 million (2020: US$3.6 million). Other income in 2020 also consisted of a settlement sum of US$1.0 million received from Teikoku Oil (Con Son) Co. Ltd, a subsidiary of Inpex Corporation, to resolve the dispute between both parties over the Block 05-1 PSC.

For the purpose of the consolidated statement of cash flows, net foreign exchange gain in current year includes net unrealised gain of US$1.8 million.

Litigation income in 2020 represented the arbitration award granted by Singapore International Arbitration Centre in favour to the Group in response to a breach of the SC56 farm out agreement by Total E&P Philippines BV.

15 FINANCE COSTS

	2021 USD'000	2020 USD'000
Interest expense	150	2,366
Accretion expense for asset retirement obligations (Note 35)	5,920	6,312
Interest expense on lease liabilities	1,222	3,341
Changes in provisions:		
Lemang PSC contingent payments	314	-
PenMal Assets contingent payment	124	-
Accretion expense for Stag FSO provision	-	51
Other finance costs	1,345	585
	9,075	**12,655**

Interest expense refers to the effective interest charge on the reserve based lending facility.

The fair value of the contingent payments payable to Mandala Energy Lemang Pte Ltd for the Lemang PSC acquisition were revalued to US$4.8 million as at 31 December 2021 (2020: US$4.4 million), reflecting the effect of the time value of money for the trigger events as disclosed in Note 20.

The consideration for the PenMal Assets included two separate contingent payments for US$3.0 million each if the average Dated Brent remained equal or above US$65/bbl in 2021 and US$70/bbl in 2022. The contingent payments had a fair value of US$4.3 million (see Note 19.3) on the date of acquisition. At year end, the contingent payments were revalued at US$4.4 million, resulting in an increase in the provision of US$0.1 million.

Other finance costs include accretion expense of US$1.2 million (2020: US$0.5 million) generated from an Australian Taxation Office ("ATO") 2019 repayment plan of US$43.3 million to support companies impacted by COVID-19. The repayment schedule was between December 2020 and June 2022 but the plan was fully repaid in May 2022.

16 OTHER FINANCIAL GAINS

	2021 USD'000	2020 USD'000
Change in provision:		
Montara contingent payments	-	359
Accretion income from non-current Lemang PSC VAT receivables	266	-
	266	**359**

The accretion income represents the effect of the time value of money on the non-current Lemang PSC VAT receivables. The fair value of the VAT receivables were revalued to US$4.7 million as at 31 December 2021 (2020: US$4.4 million).

The change in provision represents the change in the fair value of the Montara contingent payments. The Group derecognised the Montara 2020 contingent payment in 2020 as the trigger event to crystallise this payment did not arise. The fair values of the remaining Montara contingent payments have been valued at US$ nil, as the possibility of realisation is remote.

17 INCOME TAX EXPENSE

	2021 USD'000	2020 USD'000
Current tax		
Corporate tax (credit)/charge	(486)	11,020
Overprovision in prior year	(270)	(1,030)
	(756)	**9,990**
Australian petroleum resource rent tax ("PRRT")	(1,374)	1,678
Malaysian petroleum income tax ("PITA")	9,469	-
	7,339	**11,668**
Deferred tax		
Corporate tax	5,247	(4,026)
PRRT	3,371	(4,702)
PITA	(1,135)	-
	7,483	**(8,728)**
	14,822	**2,940**

Jadestone Energy Inc., the former ultimate holding company, was a resident in the Province of British Columbia and paid no Canadian tax. The Group has no operating business in Canada. Following the completion of the internal organisation (Note 2), Jadestone Energy plc became the ultimate holding company on 23 April 2021. Jadestone Energy plc's tax domicile is Singapore and is subjected to Singapore's domestic corporate tax rate of 17%. Subsidiaries are resident for tax purposes in the territories in which they operate.

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

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

During the year, Stag recorded a net PRRT expense of US$2.0 million (2020: PRRT credit of US$3.0 million), after utilising PRRT carried forward credits of US$4.7 million from 2020.

As at year end, Montara has US$3.4 billion (2020: US$3.3 billion) of unutilised PRRT carried forward credits. Based on management's latest forecasts, the augmentation on historic accumulated PRRT net losses will more than offset PRRT that would otherwise arise on future PRRT taxable profits. Accordingly, Montara is not anticipated to incur any PRRT expense.

PenMal Assets recorded PITA expense of US$8.3 million since the completion of acquisition on 1 August 2021.

The tax recoverable of US$9.4 million as at year end represents PITA receivable of which US$5.1 million arose from pre-economic effective date of the PenMal Assets acquisition which will be payable to SapuraOMV following the receipt from tax refund. The Group has recognised the payable to SapuraOMV as at year end.

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

	2021 USD'000	2020 USD'000
Profit/(Loss) before tax	**1,080**	**(57,238)**
Tax calculated at the domestic tax rates applicable to the profit/loss in the respective countries (Australia 30% & 40%, Malaysia 24% & 38%, New Zealand 28%, Canada 27% and Singapore 17%)	3,948	(9,198)
Effects of non-deductible expenses	3,803	16,192
Effect of PRRT/PITA tax expense	8,095	1,678
Deferred PRRT/PITA tax expense/(credit)	2,238	(4,702)
Effect of unutilised tax losses recognised as deferred tax asset	(2,992)	-
Overprovision in prior year	(270)	(1,030)
Tax expense for the year	**14,822**	**2,940**

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

	2021 USD'000	2020 USD'000
Other comprehensive loss – deferred tax		
Income tax credit related to carrying amount of hedged item	-	(1,583)

18 LOSS PER ORDINARY SHARE

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

	2021 USD'000	2020 USD'000
Loss for the purposes of basic and diluted per share, being the net loss for the year attributable to equity holders of the Company	(13,742)	(60,178)

	2021 Number	2020 Number
Weighted average number of ordinary shares for the purposes of basic EPS	463,567,519	461,309,862
Effect of diluted potential ordinary shares – share options	-	-
Weighted average number of ordinary shares for the purposes of dilutive EPS	**463,567,519**	**461,309,862**

In 2021, 6,640,985 (2020: 4,679,402) of weighted average potentially dilutive ordinary shares available for exercise from in the money vested options, associated with share options were excluded from the calculation of diluted EPS, as they are anti-dilutive in view of the loss for the year.

In 2021, 899,306 (2020: 651,687) of weighted average contingently issuable shares associated under the Company's performance share plan based on the respective performance measures up to year end were excluded from the calculation of diluted EPS, as they are anti-dilutive in view of the loss for the year.

In 2021, 140,965 (2020: 68,480) of weighted average contingently issuable shares under the Company's restricted share plan were excluded from the calculation of diluted EPS, as they are anti-dilutive in view of the loss for the year.

Loss per share (US$)	2021	2020
– Basic and diluted	(0.03)	(0.13)

19 ACQUISITION OF SAPURAOMV (PM) INC.

19.1 Effective date and acquisition date

On 30 April 2021, the Group executed a sale and purchase agreement ("SPA") with SapuraOMV Upstream (PM) Sdn Bhd ("SapuraOMV") to acquire the entire share capital of SapuraOMV (PM) Inc. for a cash consideration of US$20.0 million, comprising a headline price of US$9.0 million, plus customary adjustments of US$11.0 million (see Note 19.3). There are two separate potential contingent payments to SapuraOMV of US$3.0 million each related to the annual average Dated Brent price equal or above US$65/bbl in 2021 and US$70/bbl in 2022.

The acquisition completed on 1 August 2021, following the satisfaction of all conditions precedent. The economic effective date of the acquisition, as set out in the SPA, was 1 January 2021, meaning the Group was entitled to all net cash generated since 1 January 2021 up to the completion date. As a result, at completion on 1 August 2021, the Group obtained cash held by SapuraOMV (PM) Inc. of US$29.2 million, resulting in net cash receipts of US$9.2 million.

The legal transfer of ownership and control of SapuraOMV (PM) Inc. occurred on the date of completion, 1 August 2021 (the Acquisition Date). It was at this point that the Group became able to control the key operating decisions relating to the acquired entity. Therefore, for the purpose of calculating the purchase price allocation, management has determined the fair value adjustments using the balance sheet of the SapuraOMV (PM) Inc. as at the completion date of 1 August 2021.

On 3 August 2021, the name of SapuraOMV (PM) Inc. was changed to Jadestone Energy (PM) Inc. ("JEPM").

19.2 Business acquisition

Management has concluded that the acquisition of JEPM is that of a business as defined in IFRS 3 *Business Combinations*. JEPM contains inputs and processes, which when combined has the ability to contribute to the creation of outputs (oil and gas). Accordingly, the transaction has been accounted for as a business combination.

As a result, the Group has applied the acquisition method of accounting as at the Acquisition Date. A purchase price allocation exercise was performed to identity, 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.

19.3 Fair value of consideration transferred

The fair value consideration for the PenMal Assets reflected a net cash receipt of US$9.2 million, as set out below:

	USD'000
Asset purchase price	9,000
Crude inventory value	3,236
Cash at bank, 1 January 2021	8,091
Closing statement adjustments	(294)
Cash payment on Acquisition Date	**20,033**
Less: cash and bank balances acquired, 1 August 2021	(29,252)
Net cash receipts from the acquisition	**(9,219)**

The crude inventory was measured at the market value and the cash at bank represents the cash on hand, as at the economic effective date of 1 January 2021.

The closing statement adjustments relates to permitted leakages of US$0.3 million of audited intercompany charges that relate to SapuraOMV Group (pre 1 January 2021).

In addition, there were two deferred potential contingent payments of US$3.0 million each, payable depending on the outcome of two trigger events, namely that the average Dated Brent oil price would equal or exceed US$65/bbl in 2021 and US$70/bbl in 2022. If either or both events occur, the respective contingent payment would be paid within 30 days from the end of each calendar year.

Management has assessed the fair value of the deferred contingent payments using a Monte Carlo option simulation model, which considered inputs such as spot Brent oil price at completion date, the risk-free rate, a volatility factor and the length of time the contingent payments apply. The fair value of both contingent payments was assessed to be US$4.3 million, representing US$3.0 million and US$1.3 million for the 2021 and 2022 deferred contingent payments, respectively. The 2022 contingent payment reflects a discount of 57% from the original value, reflecting the time value of money and the likelihood of the trigger event occurring. The assessment of 2022 contingent payment was performed as at 1 August 2021, based on the facts and circumstances existed as at that date. Subsequent to year end, the oil prices have seen an abnormal increase, accordingly the Group is likely to pay the 2022 contingent payment in full.

The 2021 contingent payment of US$3.0 million crystalised at year end as the average Dated Brent oil price exceeded US$65/bbl, hence the amount was recognised as an accrual at year end. The amount was paid in January 2022.

Fair value of purchase consideration	**USD'000**
Asset purchase price	9,000
Crude inventory value	3,236
Cash at bank	8,091
Closing statement adjustments	(294)
Cash payment on acquisition date	**20,033**
Working capital adjustments	(1,059)
Deferred contingent considerations	4,305
Total	**23,279**

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 SapuraOMV during the sales process period and there were a number of other interested parties in the formal sale process;
- Knowledgeable, willing but not anxious parties: both the Group and SapuraOMV 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 SapuraOMV. Both parties had engaged their own professional advisors. There is no reason to conclude that the transaction was not transacted at arm's length.

19.4 Assets acquired and liabilities assumed at the date of acquisition

During the year, the Group has completed the purchase price assessment ("PPA") to determine the fair values of the net assets acquired within the stipulated time period of 12 months from the Acquisition Date, in accordance with IFRS 3. The adjusted fair values of the identifiable assets and liabilities as at the Acquisition Date were:

	USD'000
Asset	
Non-current assets	
Oil and gas properties (Note 22)	21,744
Other receivables	42,092*
Deferred tax assets	10,343
Current assets	
Inventories	2,853
Trade and other receivables	21,276
Tax recoverable	10,226
Cash and bank balances	29,252
	137,786
Liabilities	
Non-current liabilities	
Provision for asset retirement obligations (Note 35)	91,552
Deferred tax liabilities	6,177
Current liabilities	
Trade and other payables	16,778
	114,507
Net identifiable assets acquired	**23,279**

* Other receivables represent the accumulated CESS paid to the Malaysian regulator for operated licences, which will be reclaimable by the Group in the future following the commencement of decommissioning activities.

19.5 Impact of acquisition on the results of the Group

Included in the Group's revenue for the year was US$46.6 million attributable to the PenMal Assets. Included in the Group's after tax loss for the year was a profit of US$6.5 million attributable to the PenMal Assets.

Acquisition-related costs amounting to US$0.7 million have been excluded from the consideration transferred and have been recognised as an expense in the period, within "other expenses" line item in the consolidated statement of profit or loss and other comprehensive income.

Had the business combination been effected at 1 January 2021, and based on the performance of the business during 2021 under SapuraOMV's operatorship, the Group would have generated revenues of US$107.2 million and an estimated net profit after tax of US$29.6 million.

The Directors of the Group consider these "pro-forma" numbers to represent an approximate measure of the performance of the combined Group on an annualised basis and to provide a reference point for comparison in future periods.

20 ACQUISITION OF LEMANG PSC

20.1 Acquisition date

In 2020, the Group executed an acquisition agreement with Mandala Energy Lemang Pte Ltd ("Mandala Energy") to acquire an operated 90% interest in the Lemang PSC, for a total cash consideration of US$12.0 million, including closing statement adjustments and subsequent contingent payments. The acquisition closed on 11 December 2020 ("Closing Date"), following the completion of various conditions precedent at the time of signing the acquisition agreement.

20.2 Asset acquisition

Management has concluded that the acquisition of the Lemang PSC is an asset acquisition as the Lemang PSC does not come with an organised workforce, and the Group does not take over any process in the form of a system, protocol or standards to contribute to the creation of outputs. Hence, the acquisition does not fall within the definition of a business acquisition under IFRS 3. Therefore, the assets acquired and liabilities assumed in the acquisition of the Lemang PSC, and the consideration transferred have been measured at fair value, in accordance to the definition of fair value under IFRS 13 *Fair Value Measurement*.

20.3 Fair value of consideration transferred

The fair value consideration of the Lemang PSC reflected net cash outflows of US$12.0 million, as set out below:

	USD'000
Asset purchase price	12,000
Closing statement adjustments	55
Cash payment on acquisition date	**12,055**
Less: cash and bank balances acquired	(96)
Net cash outflows on acquisition	**11,959**

The total net cash outflows on acquisition reflects the net receipts arising from the working capital adjustments at the Closing Date.

There are additional potential deferred contingent payments, dependent on the future outcome of a number of trigger events. Please refer to Note 20.5 for the full disclosure of all the contingent payments along with the management's assessment. Management has reviewed all the contingent payments, and at the date of acquisition recorded an amount of US$4.4 million at fair value for the following two contingent events:

- First gas date: US$5.0 million; and
- The accumulated receipts of VAT reimbursements received which are attributable to the Lemang Block as at the Closing Date, exceeding an aggregate amount of US$6.7 million on a gross basis: US$0.7 million.

Management has assessed the fair value of the above contingent consideration based on the estimated timing of first gas date, and the estimated receipts from the VAT receivables. This implies the fair value of the contingent considerations to be US$3.9 million and US$0.5 million, respectively, totalling US$4.4 million as at Closing Date. This reflects a discount of 23% and 20% for the respective contingent consideration payments arising from the time value of money and the likelihood of the trigger event occurring. There is no change to the fair value as at 2020 year end due to the short timeframe from the Closing Date up to 2020 year end. As at 31 December 2021, the fair value of the contingent payments are valued at US$4.8 million, reflecting the time value of money. The contingent payments are not expected to be paid before 2024 and accordingly have been classified as non-current liability.

The Group has not recognised other contingent payments associated with the acquisition of the Lemang PSC as management considers the probability of outflow to be remote.

Fair value of purchase consideration	USD'000
Asset purchase price	12,000
Closing statement adjustment	55
Cash payment on acquisition date	**12,055**
Deferred contingent consideration	4,436
Total	**16,491**

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 Mandala Energy during the sales process period and there a number of other interested parties in the formal sale process;
- Knowledgeable, willing but not anxious parties: both the Group and Mandala Energy are experienced oil and gas operators under no duress. 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 Mandala Energy. Both parties had engaged their own professional advisors so there is no reason to conclude that the transaction was not transacted at arm's length.

20.4 Assets acquired and liabilities assumed at the date of acquisition

The fair value of the identifiable assets and liabilities of the Lemang PSC, acquired and assumed as at the date of acquisition, were:

	Total USD'000
Asset	
Non-current assets	
Intangible exploration assets (Note 21)	14,825
VAT receivables	4,393
Current assets	
Trade and other receivables	398
Inventories	3
Cash and bank balances	96
	19,715
Liabilities	
Non-current liabilities	
Provision for asset retirement obligations (Note 35)	2,741
Current liabilities	
Trade and other payables	483
	3,224
Net identifiable assets acquired	**16,491**

The provision for asset restoration obligations assumed by the Group is associated with oil production by Mandala Energy that ceased prior to the acquisition in December 2020. The obligation was assumed following the acquisition, and the decommissioning expenditure is expected to be incurred from 2034, at the end of the life of the planned gas development.

20.5 Deferred contingent consideration

No.	Trigger event	Consideration	Management's rationale
1	First gas date	US$5.0 million	Please refer to 20.3 above.
2	The accumulated VAT receivables reimbursements which are attributable to the unbilled VAT in the Lemang Block as at the Closing Date, exceeding an aggregate amount of US$6.7 million on a gross basis.	US$0.7 million	Please refer to 20.3 above.
3	First gas date on or before 31 March 2023.	US$3.0 million	It is unlikely that the first gas date will be on or before 31 March 2023.
4	Total actual Akatara Gas Project “close out” costs set out in the AFE(s) approved pursuant to a joint audit by SKK MIGAS and BPKP is less than, or within 2% of the “close out” development costs set out in the approved revised plan of development for the Akatara Gas Project.	US$3.0 million	The Akatara Gas Project has not been sanctioned as at year end due to ongoing preparation of project approval documentation. It is unknown if the future close out costs will be less than or within 2% of the budgeted amount and it is unable to be reliably measured as at year end.
5	The average Saudi CP in the first year of operation is higher than US$620/MT.	US$3.0 million	Saudi CP is not expected to be above US$620/MT throughout the PSC term to 2037.
6	The average Saudi CP in the second year of operation is higher than US$620/MT.	US$2.0 million	Saudi CP is not expected to be above US$620/MT throughout the PSC term to 2037.
7	The average Dated Brent price in the first year of operation is higher than US$80/bbl.	US$2.5 million	The Dated Brent price is not expected to be above US$80/bbl throughout the PSC term to 2037.
8	The average Dated Brent price in the second year of operation is higher than US$80/bbl.	US$1.5 million	The Dated Brent price is not expected to be above US$80/bbl throughout the PSC term to 2037.
9	A plan of development for the development of a new discovery made, as a result of the remaining exploration well commitment under the PSC, is approved by the relevant government entity.	US$3.0 million	There are no prospects or leads presently selected for the exploration well commitment. As at year end, it is not probable that this contingent consideration trigger will be met.
10	The plan of development described in item 9 above is approved by the relevant government entity and is based on reserves of no less than 8.4mm barrels (on a gross basis).	US$8.0 million	There are no prospects or leads presently selected for the exploration well commitment. As at year end, it is not probable that this contingent consideration trigger will be met.

21 INTANGIBLE EXPLORATION ASSETS

	USD'000
Cost	
As at 1 January 2020	117,440
Acquisition of Lemang PSC (Note 20)	14,825
Additions	18,860
As at 31 December 2020	**151,125**
Additions	3,934[(a)]
Change in asset retirement obligations (Note 35)	(44)[(b)]
Reversal	(6,059)[(c)]
Written off	(55,715)[(d)]
As at 31 December 2021	**93,241**
Impairment	
As at 1 January 2020	-
Additions (Note 13)	50,455
As at 31 December 2020	**50,455**
Written off	(50,455)
As at 31 December 2021	-
Net book value	
As at 1 January 2020	**117,440**
As at 31 December 2020	**100,670**
As at 31 December 2021	**93,241**

(a) For the purpose of the consolidated statement of cash flows, current year expenditure on intangible exploration assets of US$0.1 million remained unpaid as at 31 December 2021 (2020: US$4.6 million).

(b) The change in asset retirement obligations of US$0.04 million relates to assets at the Lemang PSC.

(c) The US$6.0 million reversal during the year relates to an overprovision of costs owed to a third party contractor. The overprovision was identified following an assessment of actual costs incurred.

(d) In November 2020, Total, as operator of SC56 voluntarily surrendered a combined 100% interest in SC56 to the Philippines Department of Energy ("DOE"). As a result, the carrying value of US$50.4 million was impaired in Q4 2020. The DOE acknowledged the relinquishment in February 2021 and the exit obligation terms were agreed in June 2021. Accordingly, the carrying value was formally written off in 2021.

The Group has also written off intangible exploration assets of US$5.3 million during the year (Note 11).

22 OIL AND GAS PROPERTIES

	USD'000
Cost	
As at 1 January 2020	492,985
Changes in asset restoration obligations (Note 35)	(725)
Additions	4,732
As at 31 December 2020	**496,992**
Changes in asset restoration obligations (Note 35)	23,894
Acquisition of PenMal Assets (Note 19)	21,744
Additions	52,864*
As at 31 December 2021	**595,494**
Accumulated depletion and amortisation	
As at 1 January 2020	**111,311**
Charge for the year	68,005
As at 31 December 2020	**179,316**
Charge for the year	62,586
As at 31 December 2021	**241,902**
Net book value	
As at 1 January 2020	**381,674**
As at 31 December 2020	**317,676**
As at 31 December 2021	**353,592**

* The additions consist of cash payments of US$51.4 million and capitalisation of depreciation of US$1.5 million associated with right-of-use assets in Australia in accordance with IAS 16, both associated with the drilling of the H6 infill well at Montara.

23 PLANT AND EQUIPMENT

	Computer equipment USD'000	Fixtures and fittings USD'000	Materials and spares USD'000	Total USD'000
Cost				
As at 1 January 2020	2,824	1,315	-	4,139
Disposal	280	193	-	473
As at 31 December 2020	**3,104**	**1,508**	**-**	**4,612**
Additions	450	232	-	682
Written off	-	(169)	-	(169)
Transfer	-	-	7,209	7,209*
As at 31 December 2021	**3,554**	**1,571**	**7,209**	**12,334**
Accumulated depreciation				
As at 1 January 2020	1,334	1,025	-	2,359
Charge for the year	323	278	-	601
As at 31 December 2020	**1,657**	**1,303**	**-**	**2,960**
Charge for the year	302	206	-	508
Written off	-	(97)	-	(97)
As at 31 December 2021	**1,959**	**1,412**	**-**	**3,371**
Net book value				
As at 1 January 2020	**1,490**	**290**	**-**	**1,780**
As at 31 December 2020	**1,447**	**205**	**-**	**1,652**
As at 31 December 2021	**1,595**	**159**	**7,209**	**8,963**

* The transfer represents the material and spares that are not expected to be consumed within the next 12 months from the year end. The reclassification amount is net of allowance of slow moving items of US$1.9 million as disclosed in Note 11.

24 RIGHT-OF-USE ASSETS

	Production assets USD'000	Transportation and logistics USD'000	Buildings USD'000	Total USD'000
Cost				
As at 1 January 2020	29,339	42,320	3,004	74,663
Additions	-	419	472	891
Termination	(29,339)	-	(307)	(29,646)
Adjustment	-	(394)	-	(394)
As at 31 December 2020	**-**	**42,345**	**3,169**	**45,514**
Additions	-	1,200	1,654	2,854
As at 31 December 2021	**-**	**43,545**	**4,823**	**48,368**
Accumulated depreciation				
As at 1 January 2020	5,334	8,519	1,023	14,876
Charge for the year	3,837	11,419	972	16,228
Termination	(9,171)	-	(92)	(9,263)
As at 31 December 2020	**-**	**19,938**	**1,903**	**21,841**
Charge for the year	-	11,470*	1,205	12,675*
As at 31 December 2021	**-**	**31,408**	**3,108**	**34,516**
Net book value				
As at 1 January 2020	**24,005**	**33,801**	**1,981**	**59,787**
As at 31 December 2020	**-**	**22,407**	**1,266**	**23,673**
As at 31 December 2021	**-**	**12,137**	**1,707**	**13,852**

* The amount includes US$1.5 million which has been capitalised within oil and gas properties as the related right-of-use assets were used as part of the drilling of the H6 infill well at Montara (see Note 22).

The Group leases several assets including helicopters, a supply boat, logistic facilities for the Montara field, and buildings. The average lease term is 3 years.

The maturity analysis of lease liabilities is presented in Note 36.

	2021 USD'000	2020 USD'000
Amount recognised in profit or loss		
Depreciation expense on right-of-use assets	11,191	16,228
Interest expense on lease liabilities	1,222	3,341
Expenses relating to short-term leases	63,734	3,113
Expense relating to leases of low value assets	81	31

At 31 December 2021, the Group has not committed to any short-term leases (2020: US$8.1 million).

The total cash outflow for leases amount to US$13.0 million (2020: US$18.6 million).

The additions of right-of-use assets during the year represent the extension of the Group's ongoing right-of-use assets and entered into a five-year lease to rent an Australian office building to replace an expired lease.

25 INTERESTS IN OPERATIONS

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

Contract Area	Date of expiry	Held by	Place of operations	Group effective working interest % as at 31 December 2021	2020
Montara Oilfield	Indefinite	Jadestone Energy (Eagle) Pty Ltd	Australia	100	100
Stag Oilfield	25 Aug 2039	Jadestone Energy (Australia) Pty Ltd	Australia	100	100
PM329	8 December 2031	Jadestone Energy (PM) Inc.	Malaysia	70	-
PM323	14 June 2028	Jadestone Energy (PM) Inc.	Malaysia	60	-
PM318	24 May 2034	Jadestone Energy (PM) Inc.	Malaysia	50	-
AAKBNLP	24 May 2024	Jadestone Energy (PM) Inc.	Malaysia	50	-
46/07	29 Jun 2035	Mitra Energy (Vietnam Nam Du) Pte Ltd	Vietnam	100	100
51	10 Jun 2040	Mitra Energy (Vietnam Tho Chu) Pte Ltd	Vietnam	100	100
Lemang	17 Jan 2037	Jadestone Energy (Lemang) Pte Ltd	Indonesia	90	90
SC57	14 Sept 2055	Mitra Energy (Philippines SC-57) Ltd	Philippines	-	21

* In 2006, the Group executed an agreement with the Philippines National Oil Company ("PNOC") to acquire a 21% working interest in SC57. The acquisition required the approval of the Office of the President of the Philippines and in December 2021 PNOC advised that such approval will not be granted by the Philippines Department of Energy. The Group is now seeking reimbursement from PNOC for costs of approximately US$0.9 million which it incurred in relation to a 2008 seismic acquisition campaign. This is not recognised as a receivable as at year end as it is not sufficiently certain that the amount will be received.

26 DEFERRED TAX

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

	Australian PRRT USD'000	Malaysian PITA USD'000	Tax depreciation USD'000	Derivatives financial instruments USD'000	Total USD'000
As at 1 January 2020	13,215	-	(60,445)	(1,583)	(48,813)
Credited to profit or Loss (Note 17)	4,702	-	4,026	-	8,728
Credited to OCI	-	-	-	1,583	1,583
As at 31 December 2020	**17,917**	**-**	**(56,419)**	**-**	**(38,502)**
Charged to profit or loss (Note 17)	(3,371)	1,135	(5,247)	-	(7,483)
Acquisition of PenMal Assets (Note 19)	-	4,166	-	-	4,166
As at 31 December 2021	**14,546**	**5,301**	**(61,666)**	**-**	**(41,819)**

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

	2021 USD'000	2020 USD'000
Deferred tax liabilities	(67,097)	(58,229)
Deferred tax assets	25,278	19,727
	(41,819)	**(38,502)**

The Group has unutilised PRRT credits of approximately US$3.4 billion (2020: US$3.3 billion) available for offset against future PRRT taxable profits in respect of the Montara field. The PRRT credits remain effective throughout the production licence of Montara. No deferred tax asset has been recognised in respect of these PRRT credits, due to management's projections that there will continue to be current augmentation of PRRT credits that are more than sufficient to offset any PRRT tax to be paid. As PRRT credits are utilised based on a last-in-first-out basis, the unutilised PRRT credits of approximately US$3.4 billion (2020: US$3.3 billion) will not be utilised given the forecasted augmentation, and are therefore not recognised as a deferred tax asset.

27 INVENTORIES

	2021 USD'000	2020 USD'000
Materials and spares	12,011	21,245
Less: allowance for slow moving (Note 11)	(2,060)	(1,329)
	9,951	**19,916**
Crude oil inventories	13,348	25,445
	23,299	**45,361**

The cost of inventories recognised as an expense during the year for lifted volumes, comprising production costs excluding workovers, Malaysian supplementary payments and tariffs and transportation costs, plus depletion expense of oil & gas properties, and plus depreciation of right-of-use assets deployed for operational use, is US$200.4 million (2020: US$166.9 million).

28 TRADE AND OTHER RECEIVABLES

	2021 USD'000	2020 USD'000
Current assets		
Trade receivables	9,143	106
Prepayments	3,770	2,012
Other receivables and deposits	13,281	4,273
Amount due from joint arrangement partners (net)	2,203	-
Underlift crude oil inventories	6,855	-
GST/VAT receivables	2,699	719
	37,951	**7,110**
Non-current asset		
Other receivables		
Acquisition of PenMal Assets (Note 19)	42,092	-
Change in asset restoration obligations (Note 35)	(672)	-
Cess paid	306	-
	41,726	**-**
Prepayment	2,000	-
VAT receivables	4,774	4,404
	48,500	**4,404**
	86,451	**11,514**

Trade receivables arise from revenues generated in Australia and Malaysia. The average credit period is 30 days (2020: 30 days). All outstanding receivables as at 31 December 2021 and 2020 have been fully recovered in 2022 and 2021, respectively.

Other receivables in current year consist of insurance claim receivable of US$10.3 million on the well control claim for the Skua 11 well workovers.

Amount due from joint arrangement partners represents cash calls receivable from the Malaysian and Indonesian joint arrangement partners, net of joint arrangement expenditures. The amount due from the Malaysian joint arrangement partner is unsecured, with a credit period of 15 days. A notice of default will be served to the joint arrangement partner if the credit period is exceeded, which will become effective seven days after service of such notice if the outstanding amount remains unpaid. Interest of 3% per annum will be imposed on the outstanding amount, starting from the effective date of default. The outstanding receivable has been fully recovered in 2022.

The amount due from the Indonesian joint arrangement partner is unsecured, with a credit period of 7 days. A notice of default will be served to the joint arrangement partner if the credit period is exceeded, which will become effective seven days after service of such notice if the outstanding amount remains unpaid. An interest at LIBOR plus 3% per annum will be imposed on the outstanding amount, starting from the effective date of default.

Non-current other receivables represent the accumulated cess payment paid to the Malaysian regulator for the operated licences. The Malaysian require upstream operators to contribute periodic cess payments to a cess abandonment fund throughout the production life of the upstream oil and gas assets. This is to ensure there is sufficient funds available for decommissioning expenditures activities at the end of field life. The cess payment amount is assessed based on the estimated future decommissioning expenditures.

The non-current VAT receivables are associated with the Lemang PSC. It is classified as a non-current asset as the recovery of the VAT receivables is dependent on the share of revenue entitlement by the Indonesian government after the commencement of gas production, which is estimated to occur after 2022.

There are no trade receivables older than 30 days.

29 CASH AND BANK BALANCES

	2021 USD'000	2020 USD'000
Cash and bank balances	117,865	89,441
Less: restricted cash	-	(8,445)
Cash and cash equivalents in the consolidated statement of cash flows	**117,865**	**80,996**

Cash and bank balances in 2021 contains a restricted cash balance of US$0.4 million and US$0.5 million in relation to a deposit placed for bank guarantee with respect to the PenMal Assets and Australian office building, respectively.

Restricted cash in 2020 included US$7.4 million related to the Group's reserve based lending arrangement (Note 37). As part of the agreement, the Group had to retain an aggregate amount of principal, interest, fees and costs payable at each quarter-end in a debt service reserve account ("DSRA"). The US$7.4 million was deposited in the DSRA as at 31 December 2020. The DSRA was released on 31 March 2021, upon the repayment of the final balance outstanding on the loan. Restricted cash in 2020 also contained a performance bank guarantee of US$1.0 million, placed with the Indonesian regulator in relation to a joint study agreement ("JSA"). The amount was released to the Group during Q3 2021 upon the completion of the JSA.

The restricted cash of US$10.0 million held by the Group in 2019, in support of a bank guarantee to a key supplier in respect of Stag's FSO vessel, was released to the Group upon the termination of the FSO vessel lease agreement in 2020.

30 SHARE CAPITAL

	No. of shares	USD'000
Authorised ordinary shares issued and fully paid		
As at 1 January 2020	461,042,811	466,573
Issued during the year	800,000	406
As at 31 December 2020	**461,842,811**	**466,979**
Issued during the year	3,238,427	967
Capital reduction, at £0.499 each	-	(467,387)
As at 31 December 2021	**465,081,238**	**559**

On 4 May 2021, the High Court of Justice, Business and Property Court, Companies Court in England and Wales approved the reduction of share capital of the Company pursuant to section 648 of the Act by cancelling the paid-up capital of the Company to the extent of 49.9 pence on each ordinary share of £0.50 in the issued share capital of the Company. The effective date of the capital reduction was 6 May 2021.

During the year, employee share options of 3,238,427 were exercised and issued at an average price of GB£ 0.33 per share (2020: 800,000; GB£0.33 per share).

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

Prior to the internal reorganisation on 23 April 2021, Jadestone Energy Inc. the former ultimate holding company, has issued 1,806,666 shares, resulting to the total outstanding number of shares at 463,649,477 as at 23 April 2021. The Company has issued 1,431,761 shares post the completion of the internal reorganisation.

31 DIVIDENDS

The parent company has sufficient distributable reserves to declare dividends, despite the post-tax losses incurred during the year. The dividends declared were in compliance with the Act.

The Directors plan to recommend a final 2021 dividend of 1.34 US cents/share on 6 June 2022, equivalent to a total distribution of US$9.0 million. The dividend will be paid in July 2022.

On 9 September 2021, the Directors declared a 2021 interim dividend of 0.59 US cents/share, equivalent to 0.43 GB pence/share, based on an exchange rate of 0.7257, equivalent to a total distribution of US$2.8 million. The dividend was paid on 1 October 2021.

On 11 June 2021, the Directors declared the second interim 2020 dividend of 1.08 US cents/share, equivalent to 0.77 GB pence/share, based on an exchange rate of 0.7087, equivalent to a total distribution of US$5.0 million, or US$7.5 million in respect of total 2020 dividends. The dividend was paid on 30 June 2021.

On 10 September 2020, the Directors declared the first 2020 interim dividend of 0.54 US cents/share, equivalent to 0.42 GB pence/share, based on an exchange rate of 0.7708, equivalent to a total distribution of US$2.5 million. The dividend was paid on 30 October 2020.

32 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 (Note 2).

33 HEDGING RESERVES

	2021 USD'000	2020 USD'000
At beginning of the year	-	(3,688)
Gain arising on changes in fair value of hedging instruments during the year	-	(26,093)
Income tax related to gain recognised in other comprehensive income	-	7,828
Net gain reclassified to profit or loss	-	31,364
Income tax related to amounts reclassified to profit or loss	-	(9,411)
At end of the year	**-**	**-**

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. The Group's oil price capped swap expired on 30 September 2020 and accordingly, all cumulative deferred gains were recognised in the profit or loss.

34 SHARE-BASED PAYMENTS RESERVE

The total expense arising from share-based payments of US$1.0 million (2020: US$1.1 million) was recognised as 'administrative staff costs' (Note 8) in profit or loss for the year ended 31 December 2021.

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

34.1 Share options

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

	Options granted on	
	18 March 2021	27 April 2020
Risk-free rate	0.49% to 0.61%	0.14% to 0.16%
Expected life	5.5 to 6.5 years	5.5 to 6.5 years
Expected volatility[1]	65.2% to 67.6%	42.7% to 43.9%
Share price	GB£ 0.65	GB£ 0.44
Exercise price	GB£ 0.77	GB£ 0.44
Expected dividends	1.79%	2.94%

34.2 Performance shares

The performance measures for performance shares incorporate a balance of relative and absolute total shareholder return ("TSR") on a 70:30 basis to reward outperformance vs. peers (relative TSR) and alignment with shareholders (absolute TSR).

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

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

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

	Performance shares granted on	
	18 March 2021	27 April 2020
Risk-free rate	0.06%	0.08%
Expected volatility[1]	51.5%	66.0%
Share price	GB£ 0.77	GB£ 0.44
Exercise price	N/A	N/A
Expected dividends	2.64%	2.80%
Post-vesting withdrawal date	N/A	N/A
Early exercise assumption	N/A	N/A

34.3 Restricted shares

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

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

	Restricted shares granted on	
	18 March 2021	27 April 2020
Risk-free rate	0.08%	0.08%
Share price	GB£ 0.77	GB£ 0.44
Expected dividends	2.64%	2.80%

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

The following table summarises the options/shares under the LTI plans outstanding and exercisable as at 31 December 2021:

			Shares Options			
	Performance shares	Restricted shares	Number of options	Weighted average exercise price GB£	Weighted average remaining contract life	Number of options exercisable
As at 1 January 2020	-	-	19,867,842	0.39	8.21	7,019,480
New options/shares awards issued	695,200	101,063	6,525,000	0.44	9.83	-
Vested during the year	-	-	-	0.38	7.20	6,193,347
Exercised during the year	-	-	(800,000)	0.33	-	(800,000)
Cancelled during the year	(12,000)	-	(400,000)	0.73	-	(200,000)
As at 31 December 2020	**683,200**	**101,063**	**25,192,842**	**0.40**	**7.78**	**12,212,827**
New options/shares awards issued	1,136,512	50,570	2,852,631	0.77	9.21	-
Vested during the year	-	-	-	0.42	6.92	3,776,672
Exercised during the year	-	-	(3,238,427)	0.33	-	(3,238,427)
Cancelled during the year	(328,058)	-	(3,690,244)	0.46	-	(1,539,905)
As at 31 December 2021	**1,491,654**	**151,633**	**21,116,802**	**0.45**	**7.15**	**11,211,167**

35 PROVISIONS

	Asset restoration obligations (a) USD'000	Stag FSO (b) USD'000	Contingent payments (c) USD'000	Employees benefits (d) USD'000	Incentive scheme (e) USD'000	Others USD'000	Total USD'000
As at 1 January 2020	275,422	4,996	359	851	1,312	-	282,940
Charge to profit or loss	-	-	-	67	1,304	1,905	3,276
Acquisition of Lemang PSC	2,741	-	4,436	-	-	-	7,177
Accretion expense (Note 15)	6,312	51	-	-	-	-	6,363
Changes in discount rate assumptions (Note 22)	(725)	-	-	-	-	-	(725)
Utilised	-	-	-	(22)	(821)	-	(843)
Fair value adjustment (Note 16)	-	-	(359)	-	-	-	(359)
Reversal (Note 14)	-	(5,047)	-	-	-	-	(5,047)
As at 31 December 2020	**283,750**	**-**	**4,436**	**896**	**1,795**	**1,905**	**292,782**
Charge to profit or loss	-	-	-	-	-	202	202
Acquisition of PenMal Assets (Note 19)	91,552	-	4,305	-	-	-	95,857
Accretion expense (Note 15)	5,920	-	-	-	-	-	5,920
Changes in discount rate assumptions (Notes 21, 22 and 28)	23,178	-	-	-	-	-	23,178
Payment/Utilised	(306)	-	(3,000)	(50)	(778)	(1,516)	(5,344)
Fair value adjustment (Note 15)	-	-	438	-	-	-	438
Reversal (Note 14)	-	-	-	-	-	(389)	(389)
As at 31 December 2021	**404,400**	**-**	**6,179**	**846**	**1,017**	**202**	**412,644**
As at 31 December 2020							
Current	-	-	-	858	1,795	1,905	4,558
Non-current	283,750	-	4,436	38	-	-	288,224
	283,750	**-**	**4,436**	**896**	**1,795**	**1,905**	**292,782**
As at 31 December 2021							
Current	-	-	-	728	1,017	202	1,947
Non-current	404,400	-	6,179	118	-	-	410,697
	404,400	**-**	**6,179**	**846**	**1,017**	**202**	**412,644**

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

   The carrying value of the provision represents the discounted present value of the estimated future costs. Current estimated costs of the ARO for each of the Montara, Stag, Lemang PSC and PenMal Assets have been escalated to the estimated date at which the expenditure would be incurred, at an assumed blended inflation rate of 2.06%, 2.12%, 2.82% and range of 2.05% to 2.07%, respectively (2020: Montara: 1.52%; Stag: 1.48%; Lemang PSC: 2.54%). The estimates for each asset are a blend of assumed US and respective local inflation rates to reflect the underlying mix of US dollar and respective local dollar denominated expenditures. The present value of the future estimated ARO for each of the Montara, Stag, Lemang PSC and PenMal Assets has then been calculated based on blended risk-free rates of 1.77%, 1.91%, 5.96% and a range of 2.81% to 3.24%, respectively (2020: Montara: 1.72%; Stag: 1.78%; and Lemang PSC: 5.86%). The base estimate ARO for Montara, Stag and Lemang PSC remains largely unchanged from 2020. The ARO of PenMal Assets was assessed in 2021, based on the existing facilities and wells acquired and required to be decommissioned at the end of field life.

   Management expects decommissioning expenditures to be incurred from 2024, 2032, 2034 and 2035 onwards for PenMal Assets, Montara, Lemang PSC and Stag, respectively.

   In 2019, Jadestone Energy (Eagle) Pty Ltd, a wholly owned subsidiary of the Company entered into a deed poll with the Australian Government with regard to the requirements of maintaining sufficient financial capacity to ensure Montara's asset restoration obligations can be met when due. The deed states that the Group is required to provide a financial security in favour of the Australian Government when the aggregate remaining net after tax cash flow of the Group is 1.25 times or below the Group's estimated future decommissioning costs.

   The Malaysian and Indonesian regulators require upstream oil and gas companies to contribute to an abandonment cess fund, including making periodic cess payments, throughout the production life of the oil or gas field. The cess payment amount is assessed based on the estimated future decommissioning expenditures. The cess payment paid for non-operated licences reduces the asset restoration liability.

b) The provision for Stag FSO was reversed in 2020 following the termination of the FSO vessel lease.

c) The contingent payment of US$1.4 million represented the fair value of one contingent payment payable to SapuraOMV for the PenMal Assets acquisition, based on the outlook of Brent crude oil prices in 2022 (Note 19). The contingent payment (if triggered) will need to be made in January 2023 and accordingly has been classified as non-current liability.

   The fair value of the contingent payments payable to Mandala Energy Lemang Pte Ltd for the Lemang PSC acquisition are valued at US$4.8 million as at 31 December 2021 (2020: US$4.4 million) for the trigger events as disclosed in Note 20.

   The contingent payment of US$0.4 million for the Montara acquisition was derecognised in 2020 as the liability failed to crystallise. The Group has not recognised other contingent payments associated with Montara acquisition as the management considers the probability of outflow is remote.

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

e) The Group's performance pay incentive scheme is based on the Group's and employees' performance, and is payable annually to employees at variable percentages of their annual wage.

36 LEASE LIABILITIES

	2021 USD'000	2020 USD'000
Presented as:		
Non-current	4,504	13,305
Current	11,161	12,478
	15,665	**25,783**
Maturity analysis of lease liabilities based on undiscounted gross cash flows:		
Year 1	12,247	13,448
Year 2	3,440	11,239
Year 3	209	2,803
Year 4	221	-
Year 5	233	-
Future interest charge	(685)	(1,707)
	15,665	**25,783**

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

37 BORROWINGS

	2021 USD'000	2020 USD'000
Secured borrowings		
Reserve based lending facility	-	7,296

At the end of Q1 2021, the Group fully repaid its reserve based lending facility, making a final principal repayment of US$7.3 million (2020: US$42.8 million) and interest of US$0.1 million (2020: US$1.4 million).

The loan incurred interest at LIBOR plus 3% (2020: LIBOR plus 3%).

38 RECONCILIATION OF LIABILITIES ARISING FROM FINANCING ACTIVITIES

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

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

	Reserved based lending facility USD'000	Lease liabilities USD'000
As at 1 January 2020	49,123	62,272
Financing cash flows	(42,766)	(16,603)
New lease liabilities	-	891
Termination of leases	-	(20,777)
Interest paid	(1,427)	(1,959)
Non-cash changes - interest	2,366	1,959
As at 31 December 2020	**7,296**	**25,783**
Financing cash flows	(7,296)	(12,972)
New lease liabilities	-	2,854
Interest paid	150	(1,222)
Non-cash changes - interest	(150)	1,222
As at 31 December 2021	**-**	**15,665**

39 TRADE AND OTHER PAYABLES

	2021 USD'000	2020 USD'000
Trade payables	26,847	10,131
Other payables	7,627	2,004
Accruals	29,699	20,047
Contingent payment	3,000	-
Supplementary payment payables	1,907	-
GST/VAT payables	10	10
	69,090	**32,192**

Trade and other payables and accruals principally comprise amounts outstanding for trade and non-trade purchases and ongoing costs. The average credit period taken for purchases is 30 days (2020: less than 30) days. For most suppliers, no interest is charged on the payables in the first 30 days from the date of invoice. Thereafter, interest may be charged on outstanding balances at varying rates of interest. The Group has financial risk management policies in place to ensure that all payables are settled within the pre-agreed credit terms.

The contingent payment of US$3.0 million payable to SapuraOMV arose from the acquisition of the PenMal Assets (Note 19). The contingent payment was paid in January 2022 as the annual average Brent crude price in 2021 exceeded US$65/bbl.

40 DERIVATIVE FINANCIAL INSTRUMENTS

The Group uses derivatives to manage its exposure to oil price fluctuations. Oil hedges are undertaken using swaps, and in some cases, call options. All contracts are referenced to Dated Brent oil prices. During the year, the Group entered into commodity swaps that are carried at fair value through profit or loss ("FVTPL"). The commodity swaps expired at the end of June 2021 and the Group has not entered into any further commodity swaps. Accordingly, there are no outstanding derivative contracts for the year ended 31 December 2021.

	2021 USD'000	2020 USD'000
Derivative financial liabilities		
Carried at FVTPL		
Commodity swaps	-	(471)

The fair values of the commodity swaps in 2020 were classified as Level 2 and calculated using market prices that the Group would pay or receive to settle those swap contracts.

The following is a summary of the Group's outstanding derivative contracts in 2020:

Contract quantity	Type of contracts	Terms	Contract price	Hedge classification	Fair value asset at 31 December 2020 USD'000
Contracts designated as cash flow hedges					
27% of Group's actual 2PD production	Commodity capped swap: swap component	Oct 2018 - Sep 2020	US$78.26/bbl for Q4 2018, US$71.72/bbl for 2019 and US$68.45/bbl for the nine months to 30 September 2020	Cash flow	-
67% of swapped barrels in 2019 and in the nine months to 30 September 2020	Commodity capped swap: call component	Jan 2019 - Sep 2020	US$80.00/bbl for the nine months to 30 September 2019, then US$85.00/bbl to September 2020	Cash flow	-
Contracts that are not designated in hedge accounting relationships					
31% of Group's anticipated planned 2P production from January to March 2021	Commodity swap	Jan - March 2021	US$49.00/bbl	FVTPL	(471)

The Group's October 2018 to September 2020 capped swap programme was designated as a cash flow hedge. Critical terms of the capped swap (i.e., the notional amount, life and underlying oil price benchmark) and the corresponding Montara hedged sales were highly similar. The Group performed a qualitative assessment of the effectiveness of the capped swap contracts and concluded that the value of the capped swap and the value of the corresponding hedged items was systematically changed in opposite directions in response to movements in the underlying commodity prices.

There was, however, a source of ineffectiveness in the capped swap arrangement, arising from the slight difference in the timing of Montara's production and the settlement of the capped swap arrangement versus the crude sales. The overall change in value in the capped swap transaction arose from the hedge ineffectiveness amounted to a net loss of approximately US$4,000 in 2020, and was included in the statement of profit or loss within "other expenses" (Note 11).

The following table details the information regarding the hedged items of the commodity capped swap contracts.

Hedged items	**Change in value used for calculating hedge ineffectiveness USD'000**	**Balance in cash flow hedge reserve for continuing hedges USD'000**	**Balance in cash flow hedge reserve arising from hedging relationships for which hedge accounting is no longer applied USD'000**
2020			
Cash flow hedges			
Forecast sales	4	-	-

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

	Current period hedging gain recognised in OCI USD'000	**Amount of hedge ineffectiveness recognised in profit or loss USD'000**	**Line item in profit or loss in which hedge ineffectiveness is included**	**Amount reclassified to profit or loss due to hedged item affecting profit or loss USD'000**	**Line item in profit or loss in which reclassification adjustment is included**
2020					
Cash flow hedges					
Forecast sales	18,265	4	Other expenses	31,360	Revenue

41 FINANCIAL INSTRUMENTS, FINANCIAL RISKS AND CAPITAL MANAGEMENT

Financial assets and liabilities

Current assets and liabilities

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

Non-current assets and liabilities

The carrying amount of non-current assets and liabilities approximates their fair values.

	2021 USD'000	2020 USD'000
Financial assets		
At amortised cost		
Trade and other receivables, excluding prepayments and GST/VAT receivables	31,482	4,379
Restricted cash	-	8,445
Cash and bank balances	117,865	80,996
	149,347	**93,820**
Financial liabilities		
At amortised cost		
Trade and other payables, excluding GST/VAT payables	69,080	32,182
Lease liabilities	15,665	25,783
Borrowings	-	7,296
Contingent consideration for Lemang PSC acquisition	4,750	4,436
Contingent consideration for PenMal Assets acquisition	1,429	-
Derivative instruments carried at FVTPL	-	471
	90,924	**70,168**

Fair values are based on management's best estimates, after consideration of current market conditions. The estimates are subjective and involve judgment, and as such are not necessarily indicative of the amount that the Group may incur in actual market transactions.

Commodity price risk

The Group's earnings are affected by changes in oil prices. The Group manages this risk by monitoring oil prices and entering into commodity hedges against fluctuations in oil prices where considered appropriate.

Montara

The Group hedged 50% of its planned production volumes for the 24 months to 30 September 2020. The hedge was a capped swap, providing downside price protection via swaps, while allowing for participation in higher commodity prices via purchased call options. The call strike was set at US$80/bbl for the nine months to 30 September 2019 and US$85/bbl for the twelve months to September 2020. The swap price was set at US$78.26/bbl for Q4 2018, US$71.72/bbl for 2019 and US$68.45/bbl for the nine months to September 2020. Approximately two thirds of the swapped barrels in 2019 and 2020 had upside price participation via purchased calls. The effective date of the hedge contracts was 1 October 2018.

In December 2020, the Group entered into a commodity swap arrangement to hedge 31% of its planned production volumes from January to March 2021, to provide downside oil price protection. The swap price was set at US$49/bbl.

On 16 February 2021, the Group entered into a commodity swap arrangement to further hedge 31% of its planned production volumes from April to June 2021. The swap price was set at US$61.40/bbl.

Commodity price sensitivity

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

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

	Effect on the result before tax for the year ended 31 December 2021 USD'000	Effect on other comprehensive income before tax for the year ended 31 December 2021 USD'000	Effect on the result before tax for the year ended 31 December 2020 USD'000	Effect on other comprehensive income before tax for the year ended 31 December 2020 USD'000
Increase by 10%	-	-	(1,348)	-
Decrease by 10%	-	-	1,348	-

Foreign currency risk

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

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

In April 2020, the Group entered into a series of forward exchange contracts under which it contracted to purchase AU$10.0 million per month, from May to November 2020, at a fixed forward AU$/US$ exchange rate of 0.6344.

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

Foreign currency sensitivity

Material foreign denominated balances were as follows:

	2021 USD'000	2020 USD'000
Cash and bank balances		
Australian Dollars	6,027	8,043
Malaysian Ringgit	4,622	-
Trade and other receivables		
Australian Dollars	2,706	1,547
Malaysian Ringgit	48	-
Trade and other payables		
Australian Dollars	43,219	21,233
Malaysian Ringgit	15,094	-

A strengthening/weakening of the Australian dollar and Malaysian Ringgit by 10%, versus the functional currency of the Group, is estimated to result in the net carrying amount of Group's financial assets and financial liabilities as at year end decreasing/increasing by approximately US$4.5 million (2020: US$1.2 million), and which would be charged/credited to the consolidated statement of profit or loss.

Interest rate risk

The Group's interest rate exposure arises from some of its cash and bank balances. The Group's other financial instruments are non-interest bearing or fixed rate, and are therefore not subject to interest rate risk.

The Group holds some of its cash in interest bearing accounts and short-term deposits. Interest rates currently received are at relatively low levels. Accordingly, a downward interest rate movement would not cause significant exposure to the Group.

On 2 August 2018, the Group entered into a reserve based lending agreement with the Commonwealth Bank of Australia and Société Générale to borrow US$120.0 million, repayable quarterly to 31 March 2021. The loan was fully drawn down on 28 September 2018 and incurred interest at LIBOR plus 3%. The loan incurred establishment and other costs of US$3.2 million, which were offset against the proceeds received.

Based on the carrying value of the reserve based loan as at 31 December 2020, if interest rates had increased or decreased by 1% and all other variables remained constant, the impact on the Group's quarterly net income/(loss) before tax would be immaterial. The loan was fully repaid on 31 March 2021.

Credit risk

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

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

The Group trades only with recognised, creditworthy third parties.

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

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

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

	Note	External credit rating	Internal credit rating	12-month ("12m") or lifetime ECL	Gross carrying amount (i) USD'000	Loss allowance USD'000	Net carrying amount USD'000
2021							
Cash and bank balances	29	n.a	Performing	12m ECL	117,865	-*	117,865
Trade receivables	28	n.a	(i)	Lifetime ECL	9,143	-*	9,143
Other receivables	28	n.a	Performing	12m ECL	13,281	-*	13,281
Amount due from joint arrangement partners	28	n.a	Performing	12m ECL	2,203	-*	2,203
2020							
Cash and bank balances	29	n.a	Performing	12m ECL	89,441	-*	89,441
Trade receivables	28	n.a	(i)	Lifetime ECL	106	-*	106
Other receivables	28	n.a	Performing	12m ECL	4,273	-*	4,273

* The amount is negligible.

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

As at 31 December 2021, total trade receivables amounted to US$9.1 million (2020: US$0.1 million). The balance in 2021 and 2020 had been fully recovered in 2022 and 2021, respectively.

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

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

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

The credit risk on cash and bank balances is limited because counterparties are banks with high credit ratings assigned by international credit rating agencies. The banks are also regulated locally, and with no history of default.

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

Liquidity risk

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

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

The Group's net loss after tax for the year was US$13.7 million (2020: US$60.2 million, inclusive of non-cash SC56 impairment of US$50.4 million). Operating cash flows before movements in working capital and net cash generated from operating activities for the year ended 31 December 2021 was US$96.6 million and US$102.1 million (2020: US$86.9 million and US$84.6 million) respectively. The Group's net current assets remained positive at US$80.0 million as at 31 December 2021 (2020: US$79.5 million).

The Group believes it has sufficient liquidity to meet all reasonable scenarios of operating and financial performance for the next 18 months.

Non-derivative financial liabilities

The following table details the expected contractual maturity for non-derivative financial liabilities with agreed repayment periods. The table below has been drawn up based on the undiscounted contractual maturities of the financial liabilities, including interest, that will be paid on those liabilities, except where the Group anticipates that the cash flow will occur in a different period. The adjustment column represents the estimated future cash flows attributable to the instrument included in the maturity analysis, which are not included in the carrying amount of the financial liabilities on the consolidated statement of financial position, namely interest expense.

	Weighted average effective interest rate %	On demand or within 1 year USD'000	Within 2 to 5 years USD'000	More than 5 years USD'000	Adjustments USD'000	Total USD'000
2021						
Non-interest bearing						
Trade and other payables	-	69,080	-	-	-	69,080
Contingent consideration for Lemang PSC acquisition	-	-	4,750	-	-	4,750
Contingent Consideration for PenMal Assets acquisition	-	-	1,429	-	-	1,429
Fixed interest rate instruments						
Lease liabilities	5.847	12,247	4,103	-	(685)	15,665
		81,327	**10,282**	**-**	**(685)**	**90,924**
2020						
Non-interest bearing						
Trade and other payables	-	32,182	-	-	-	32,182
Contingent consideration for Lemang PSC acquisition	-	-	4,436	-	-	4,436
Fixed interest rate instruments						
Lease liabilities	6.049	13,448	14,042	-	(1,707)	25,783
Variable interest rate instruments						
Borrowings	7.570	7,445	-	-	(149)	7,296
		53,075	**18,478**	**-**	**(1,856)**	**69,697**

Non-derivative financial assets

The following table details the expected maturity for non-derivative financial assets. The inclusion of information on non-derivative financial assets is necessary in order to understand the Group's liquidity risk management, as the Group's liquidity risk is managed on a net asset and liability basis. The table has been drawn up based on the undiscounted contractual maturities of the financial assets, including interest that will be earned on those assets, except where the Group anticipates that the cash flow will occur in a different period. The adjustment column represents the estimated future cash flows attributable to the instrument included in the maturity analysis, which are not included in the carrying amount of the financial assets on the consolidated statement of financial position, namely interest income.

	Weighted average effective interest rate %	On demand or within 1 year USD'000	Within 2 to 5 years USD'000	Adjustments USD'000	Total USD'000
2021					
Non-interest bearing					
Trade and other receivables, excluding prepayments and GST/VAT receivables	-	31,482	-	-	31,482
Variable interest rate instruments					
Cash and bank balances	-*	117,865	-	-*	117,865
		149,347	**-**	**-***	**149,347**
2020					
Non-interest bearing					
Trade and other receivables, excluding prepayments and GST/VAT receivables	-	4,379	-	-	4,379
Variable interest rate instruments					
Restricted cash	-*	8,445	-	-*	8,445
Cash and bank balances	-*	80,996	-	-*	80,996
		93,820	**-**	**-***	**93,820**

* The effect of interest is not material.

Capital management

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

The capital structure of the Group represents the equity of the Group, comprising share capital, merger reserve and share-based payment reserve, as disclosed in Notes 30, 32 and 34, respectively.

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

Management reviews its capital management approach on an ongoing basis and believes that this approach, given the relative size of the Group, is reasonable. There were no changes in the Group's approach to capital management during the year ended 31 December 2021. The Group is not subject to externally imposed capital requirements.

	2021 USD'000	2020 USD'000
Borrowings	-	(7,296)
Cash and cash equivalents	117,865	81,996
Restricted cash	-	7,445
Cash less borrowings	**117,865**	**82,145**

Borrowings balance in 2020 related to the reserve based lending facility that was fully repaid in March 2021. The borrowings of US$7.3 million was based on the effective interest method financing costs, and excludes derivatives, as detailed in Note 37. Cash and cash equivalents in 2020 included the Montara assets' minimum working capital cash balance of US$15.0 million required under the reserve based lending facility, while restricted cash in 2020 comprised the US$7.4 million in the DSRA. The restricted cash of US$7.4 million in 2020 excluded a US$1.0 million cash collateralised for a bank guarantee placed with the Indonesian regulator in respect of the JSA entered by the Group in Indonesia because the bank guarantee was removable and can then be used to fund the business.

The Group's overall strategy remains unchanged from 2020.

Fair value measurements

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

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

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

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

Financial assets/financial liabilities	Fair value (USD'000) as at 2021 Assets	2021 Liabilities	2020 Assets	2020 Liabilities	Fair value hierarchy	Valuation technique(s) and key input(s)	Significant unobservable input(s)	Relationship of unobservable inputs to fair value
Derivative financial instruments								
1) Oil price swaps and calls (Note 40)	-	-	-	471	Level 2	Third party valuations based on market comparable information.	n.a.	n.a.
Others - contingent consideration from Lemang PSC acquisition								
2) Contingent consideration (Note 35)	-	4,750	-	4,436	Level 3	Based on the nature and the likelihood of the occurrence of the trigger events. Fair value is estimated, taking into consideration the estimated future gas production schedule, forecasted Dated Brent oil prices and Saudi CP prices and respective price volatility at the end of the reporting period, as well as the effect of the time value of money.	Gas production schedule could be changed depending on future gas contract negotiations. Expected future oil price volatility is based on an analysis of Dated Brent oil price and Saudi CP price movements as at acquisition date.	A change in gas production schedule or significant increase in Dated Brent oil prices and Saudi CP prices would result in a significant increase in the fair value.
Others - contingent consideration from PenMal Assets acquisition								
3) Contingent consideration (Notes 19, 35 and 39)	-	4,429	-	-	Level 3	Based on the nature and the likelihood of occurrence of the trigger event. Fair value is estimated using future Dated Brent oil price forecasts at the end of the reporting period, taking into account the time value of money and volatility of oil prices.	Expected future oil price volatility is based on an analysis of Dated Brent oil price movements as at the Acquisition Date.	A slight increase in Dated Brent oil prices would result in a significant increase in the fair value and vice versa.

42 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
2021					
Revenue					
Liquids revenue	293,566	45,644	-	-	339,210
Gas revenue	-	984	-	-	984
	293,566	**46,628**	**-**	**-**	**340,194**
Production cost	(182,001)	(24,522)	-	-	(206,523)
DD&A	(75,848)	(3,621)	(281)	(465)	(80,215)
Administrative staff costs	(13,364)	(1,433)	(1,612)	(8,659)	(25,068)
Other expenses	(14,970)	(2,466)	(5,875)	(2,870)	(26,181)
Other income	7,038	9	76	559	7,682
Finance costs	(7,452)	(875)	(503)	(245)	(9,075)
Other financial gains	-	-	266	-	266
Profit/(Loss) before tax	**6,969**	**13,720**	**(7,929)**	**(11,680)**	**1,080**
Additions to non-current assets	57,130	64,117	4,744	183	126,174
Non-current assets	366,959	59,532	90,938	719	518,148
2020					
Revenue					
Liquids revenue	217,938	-	-	-	217,938
Production cost	(105,338)	-	-	-	(105,338)
DD&A	(84,024)	-	(110)	(508)	(84,642)
Administrative staff costs	(10,029)	-	(2,228)	(9,646)	(21,903)
Other expenses	(15,068)	-	(9,690)	(2,160)	(26,918)
Impairment of assets	-	-	(50,455)	-	(50,455)
Other income	14,292	-	1	12,083	26,376
Finance costs	(12,625)	-	(29)	(1)	(12,655)
Other financial gains	359	-	-	-	359
Profit/(Loss) before tax	**5,505**	**-**	**(62,511)**	**(232)**	**(57,238)**
Additions to non-current assets	11,162	-	27,706	914	39,782
Non-current assets	349,292	-	97,838	945	448,075

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

Revenues arising from producing assets arose from sales to the Group's respective sole customer in Australia and Malaysia.

43 FINANCIAL CAPITAL COMMITMENTS

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

SEA portfolio PSC operational commitments

	2021 USD'000	2020 USD'000
Not later than one year	400	10,000
One to five years	12,000	2,000
More than 5 years	10,700	10,684
	23,100	**23,084**

The SEA portfolio PSC operational commitments as at 31 December 2021 amounted to US$17.3 million (2020: US$ 17.3 million), and relates to the minimum work commitment outstanding for the Block 46/07 PSC and the Lemang PSC. The operational commitments also include training commitment of US$5.8 million (2020: US$5.8 million), for the Block 46/07 PSC, Block 51 PSC and the PenMal Assets.

Work commitment

Under the terms of the Block 46/07 PSC, Jadestone is committed to drill one more appraisal well on the block. The Group plans to drill an appraisal well on the Nam Du field to facilitate transition of 3C resource to 2C status. This well would be retained for future use as a Nam Du gas producer. Following the Group's announcement to delay the project in 2020, the Group obtained Vietnam Government approval on 14 September 2021 for a further extension of three years to 29 June 2024 in order to align drilling of the appraisal well with development of Nam Du/U Minh. Discussions are continuing with Petrovietnam to agree a gas production profile for the development, as a precursor to a gas sales contract, and ultimately attaining government sanction for the field development.

As part of the acquisition under the terms of the Lemang PSC, the Group, as the operator, has inherited unfulfilled work commitments of US$7.3 million consisting of one exploration well and a 3D seismic programme. The work commitments should have been completed during the exploration phase of the PSC by the previous owner. It has been agreed with the Indonesian regulator that the work commitments can be completed after first gas in 2024 but before the end of 2026.

Training commitment

Under the terms of the Block 46/07 PSC and Block 51 PSC, the Group commits to pay an annual training commitment amount of US$0.4 million to Petrovietnam until the expiration of the respective PSC licence. The training commitment amount is for the purpose of developing the local employees in the oil and gas industry.

As part of the acquisition under the terms of the PenMal Assets, the Group has inherited net training commitments of US$0.3 million and US$0.1 million for PM323 PSC and PM318 PSC, respectively. Funds provided with respect to this training commitment are applied to the development of local employees in the oil and gas industry. The training commitments are required to be completed before the expiration of the respective PSC.

Capital commitments

The Group has the following capital commitments for expenditure that were contracted for at the end of the reporting year but not recognised as liabilities for Stag and Montara:

	2021 USD'000	2020 USD'000
Not later than one year	5,254	8,977

The capital commitment of US$5.3 million as at 2021 year end predominately arose from long leads for 50H and 51H drilling programme at Stag, which is scheduled to occur in the middle of 2022. The 2020 capital commitment of US$9.0 million mainly related to drilling of Montara H6 infill well and Skua 12 well planning expenditure.

44 CONTINGENT LIABILITY

Legal disputes

The Group has an ongoing legal dispute with a third party contractor over a long term contract. The Group disputes the claims from the third party contractor and requested a refund for an overpaid milestone payment against the contractor. The contractor commenced a legal proceeding against the Group in the Singapore High Court that ruled in favour of Jadestone. Following, the contractor appealed the High Court decision and the appeal was dismissed. The contractor may initiate arbitration proceeding against Jadestone in the future but has not commenced an action as at the reporting date. The Group may be liable for US$6.0 million in the future, if the contractor initiates the arbitration proceeding and succeed. At this time, the management does not consider it to be probable and no provision is recognised in the financial statements.

45 EVENTS AFTER THE END OF THE REPORTING PERIOD

Russian military actions

On 24 February 2022 Russia commenced military actions against Ukraine. Following, multiple countries around the world have imposed different forms of sanctions against Russia. The Group has assessed the sanctions imposed by the countries that the Group is operating within and concluded that the sanctions had no impact to the operations of the Group.

The Group is monitoring the rapidly evolving sanctions situation and will perform regular assessments to identify any potential impact in the future.

Suspension of PenMal Assets's non-operated floating production storage and offloading ("FPSO")

In February 2022, the Bunga Kertas FPSO, deployed at the PenMal Assets' non-operated assets, had its class suspended, resulting in the cessation of production. The operator of the non-operated assets anticipates that the FPSO will have its class reinstated by July 2022 and production will be resumed by then accordingly.

Net Zero greenhouse gas emissions target update

On 1 June 2022, the Company announced its commitment to Net Zero Scope 1 and 2 greenhouse gas emissions from its operated assets by 2040. A key element of the Company's Net Zero commitment will be the development of detailed emissions reduction roadmaps for its operated assets, which will be published in 2023. Jadestone's corporate strategy of maximising recovery from existing fields while minimising their emissions, and a move towards more gas in the portfolio over time, is both responsible and appropriate in the context of managing climate change. This also strikes the right balance in delivering secure and affordable energy in parts of Southeast Asia where either an energy shortage exists or where coal may be used as an alternative. Jadestone believes it can play an important role during this period of energy transition, while also demonstrating resilience and longevity to its business. It is not possible to estimate the financial effect at this time.

46 RELATED PARTY TRANSACTIONS

Internal reorganisation

Pursuant to the internal reorganisation, on 23 April 2021, a transfer of beneficial interest agreement was entered into between Jadestone Energy Inc. ("JEI"), Jadestone Energy Holdings Limited ("JEHL") and Daniel Young, Chief Financial Officer. Under the transfer of beneficial interest agreement, JEI transferred the beneficial interest in 100,000 of the Company's shares to Daniel Young, with a corresponding reduction in the issuance of any new JEP shares due to Daniel Young in exchange for his existing JEI shares transferred to JEHL.

The purpose of this transfer was to ensure that the adjusted total outstanding number of Jadestone Energy plc shares of 463,649,477 at the completion of the internal reorganisation was exactly equal to the number of outstanding Jadestone Energy Inc. shares of 463,649,477 immediately prior to the completion of the reorganisation.

Compensation of key management personnel	**2021 USD'000**	**2020 USD'000**
Short-term benefits	7,741	6,440
Other benefits	1,295	1,006
Share-based payments	692	951
	9,728	**8,397**

The total remuneration of key management members in 2021 (including salaries and benefits) was US$9.7 million (2020: US$8.4 million) and recognised as part of the Group's administrative staff costs as disclosed in Note 8.

Compensation of Directors

	Short-term benefits[(a)] USD'000	Other benefits[(a)] USD'000	Share-based payments USD'000	Total compensation USD'000
2021				
A. Paul Blakeley	1,367	148	302	1,817
Daniel Young	748	210	(75)	883
Dennis McShane	155	-	10	165
Iain McLaren	105	-	7	112
Robert Lambert	95	-	7	102
Cedric Fontenit	95	-	7	102
Lisa Stewart	90	-	13	103
David Neuhauser	80	-	7	87
	2,735	**358**	**278**	**3,371**
2020				
A. Paul Blakeley	1,372	100	282	1,754
Daniel Young	696	190	138	1,024
Dennis McShane	119	-	18	137
Iain McLaren	79	-	11	90
Robert Lambert	70	-	11	81
Cedric Fontenit	66	-	10	76
Lisa Stewart	74	-	12	86
David Neuhauser	57	-	11	68
	2,533	**290**	**493**	**3,316**

(a) Short-term benefits comprise salary, director fee as applicable, performance pay, pension and other allowances. Other benefits comprise benefits-in-kind.

Glossary

Term	Definition
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
2C	best estimate contingent resource, being quantities of hydrocarbons which are estimated, on a given date, to be potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable
AAKBNLP	Abu, Abu Kecil, Bubu, North Lukut, and Penara oilfields
AIM	Alternative Investment Market
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
FSO	floating storage and offloading
GB pence, GBp	Great Britain pence
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
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
TCFD	Task Force on Climate-Related Financial Disclosures
US$ or USD	United States dollar