EnQuest PLC, 27 March 2025

Results for the year ended 31 December 2024 and 2025 outlook

Delivering operational excellence and diversified growth

Unless otherwise stated, all figures are in US Dollars.
Comparative figures for the Income Statement relate to the year ended 31 December 2023 and the Balance Sheet as at 31 December 2023.
Alternative performance measures are reconciled within the 'Glossary – Non-GAAP measures' at the end of the Financial Statements.

EnQuest Chief Executive, Amjad Bseisu, said:

"The Group delivered another outstanding year of operational performance in 2024, with production efficiency at 90% across the asset portfolio, representing a continuation of the excellence that defines our status as a top-quartile operator and expert in late-life asset management. After producing 40.7 Kboed in 2024, year-to-date production from our existing portfolio, as of the end of February 2025, was 43.0 Kboed (excluding Vietnam), tracking ahead of our guidance range of 40–45 Kboed, which includes approximately 5 Kboed of pro forma volumes for Vietnam. Demonstrating our differentiated operational capability across the transition lifecycle, we have continued to consolidate our position as a leading exponent of decommissioning activities, having been responsible for more than 35% of the wells plugged and abandoned in the North Sea over the past three years.

"In recent months, the Group has executed successive material growth transactions across South East Asia, providing geographic and commodity diversification within the portfolio. Our entry into Vietnam, through the Block 12W acquisition, and our increased presence in Malaysia, with the enhancement of our Seligi gas agreement and the DEWA gas development PSC award, are all underpinned by leveraging our differentiated operating capability to create asset value. As EnQuest continues to pursue growth in the UK North Sea and further potential new country entries in South East Asia, these transactions underscore our commitment to growth, a disciplined approach to M&A, and a strategy to invest capital where we identify the most favourable returns.

"Our foundation for growth is robust and we are well-positioned to transact, with our transaction ready liquidity increasing to c.$550 million at the end of February, following the latest redetermination of the Group's reserve-based lending ('RBL') facility, which remains fully undrawn. Having consistently delivered against production, operational and cost targets, we have generated material free cash flows across recent years, even during periods of reduced commodity prices. This commitment to delivery, against the backdrop of a challenging fiscal environment in the UK, has seen us reduce EnQuest net debt by more than $1.6 billion since its peak.

"Reflecting the strength of our core business and the Group's commitment to sustainable shareholder returns, I am pleased that the Board has proposed a final 2024 dividend of $15 million, subject to shareholder approval."

2024 performance

- EnQuest continued to deliver top quartile performance across its asset portfolio, which is 96% operated by the Group.
    - Group operated production efficiency c.90%, delivering average production of 40,736 Boepd (2023: 43,812 Boepd).
    - 2P reserves 168.6 MMboe (2023: 174.9 MMboe), 14.0 MMboe of production almost fully replaced by South East Asian growth.
    - Investment in fast payback projects to diversify production, manage natural field decline, lower costs and reduce emissions.
- $95.1 million reduction in EnQuest net debt, to $385.8 million (31 December 2023: $480.9 million).
    - Revenue and other income $1,180.7 million (2023: $1,487.4 million); adjusted EBITDA $672.6 million (2023: $824.7 million); reported profit after tax $93.8 million (2023: $30.8 million loss).
    - Capital investment $252.9 million (2023: $152.2 million), inclusive of $65.9 million Magnus Flare Recovery project. Decommissioning expenditure $60.5 million (2023: $58.9 million), focused on well plug and abandonment campaigns.
    - Maiden shareholder distribution in 2024, $9 million share buyback completed.

2025 outlook

- 2025 is a pivotal year, with EnQuest focused on delivering a transformational UK deal and accelerating its growth in South East Asia.
    - In the UK North Sea 2024 saw transactional activity fall, but with fiscal clarity provided by the UK Autumn Budget statement, the Group continues to progress several UK transaction processes.
    - In South East Asia, EnQuest has recently delivered the acquisition of Harbour Energy's Vietnam business (7.5 MMboe net 2P reserves, c.5.3 Kboed of pro forma 2025 production); secured the Seligi 1b gas sales agreement (13 MMboe net 2P reserves, c.6.0 Kboed from mid-2026); and been awarded the DEWA PSC (c.500 Bscf of gas in place, c.18 Kboed production potential).
    - A 34% expansion in the Group's RBL capacity at year-end redetermination has boosted EnQuest's transactional liquidity (cash and available facilities) at 28 February 2025 to $549.0 million (31 December 2024: $474.5 million).
- EnQuest is pleased to propose a 2024 final dividend of 0.616 pence per share, equivalent to c.$15 million, payable in June 2025 following shareholder approval at the Group's Annual General Meeting.
- Net Group production is expected to average between 40,000 and 45,000 Boepd (pro forma basis, including Vietnam volumes).
    - Production from the current portfolio, excluding Vietnam, averaged 43,037 Boepd to the end of February 2025.
- Operating expenditure expected to total c.$450 million; capital investment expected to total c.$190 million; Decommissioning expenditure expected to total c.$60 million, all on a pro forma basis.
    - Kraken FPSO lease rate reduces by c.70% from 1 April 2025.

Production and financial information

Macro conditions	2024	2023	Change
Brent oil price[4] ($/bbl)	80.5	82.5	-2.4%
Natural gas price[5] (GBp/Therm)	83.6	98.9	-15.5%

Alternative performance measures ('APMs')	2024	2023	Change
Production (Boepd)	40,736	43,812	-7.0%
Realised oil price ($/bbl)[1,2]	80.2	81.4	-1.5%
Average unit operating costs ($/Boe)[2]	25.3	21.9	15.5%
Adjusted EBITDA ($m)[2]	672.6	824.7	-18.4%
Cash expenditures ($m)	313.4	211.1	48.5%
Capital[2]	252.9	152.2	66.2%
Decommissioning	60.5	58.9	2.7%
Adjusted free cash flow ($m)[2]	53.2	300.0	-82.3%

	End 2024	End 2023	
EnQuest net (debt)/cash ($m)[2]	(385.8)	(480.9)	-19.8%

Statutory measures	2024	2023	Change %
Reported revenue and other operating income ($m)[3]	1,180.7	1,487.4	-20.6%
Cost of sales ($m)	(787.4)	(946.8)	-16.8%
Reported gross profit ($m)	393.3	540.7	-27.3%
Reported profit/(loss) after tax ($m)	93.8	(30.8)	n/a
Reported basic earnings/(loss) per share (cents)	5.0	(1.6)	n/a
Net cash flow from operating activities ($m)	508.8	754.2	-32.5%
Net increase/(decrease) in cash and cash equivalents ($m)	(27.7)	12.9	n/a

Notes:
[1] Including realised losses of $12.9 million (2023: realised losses of $11.3 million) associated with EnQuest's oil price hedges
[2] See reconciliation of alternative performance measures within the 'Glossary – Non-GAAP Measures' starting on page 70.
[3] Including net realised and unrealised losses of $9.8 million (2023: net realised and unrealised gains of $17.2 million) associated with EnQuest's oil price hedges
[4] Source is Reuters Factset
[5] Source is ICIS Heren NBP day-ahead

- Ends -

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Presentation to Analysts and Investors
A presentation to analysts and investors will be held at 10:00 today – London time. The presentation will be accessible via a webcast by clicking here.

The EnQuest team will be hosting a presentation via Investor Meet Company, primarily focused on the Company's retail investors on 24 April at 10:00 - London time.

The presentation is open to all existing and potential shareholders. Questions can be submitted pre-event via your Investor Meet Company dashboard up until 9am the day before the meeting or at any time during the live presentation.

Investors can sign up to Investor Meet Company for free and add to meet ENQUEST PLC via:

https://www.investormeetcompany.com/enquest-plc/register-investor

Investors who already follow ENQUEST PLC on the Investor Meet Company platform will automatically be invited.

Notes to editors

This announcement has been determined to contain inside information. The person responsible for the release of this announcement is Kate Christ, Company Secretary.

ENQUEST

EnQuest is providing creative solutions through the energy transition. As an independent energy company with operations in the UK North Sea and Malaysia, the Group's strategic vision is to be the partner of choice for the responsible management of existing energy assets, applying its core capabilities to create value through the transition.

EnQuest PLC trades on the London Stock Exchange.

Please visit our website www.enquest.com for more information on our global operations.

Forward-looking statements: This announcement may contain certain forward-looking statements with respect to EnQuest's expectations and plans, strategy, management's objectives, future performance, production, reserves, costs, revenues and other trend information. These statements and forecasts involve risk and uncertainty because they relate to events and depend upon circumstances that may occur in the future. There are a number of factors which could cause actual results or developments to differ materially from those expressed or implied by these forward-looking statements and forecasts. The statements have been made with reference to forecast price changes, economic conditions and the current regulatory environment. Nothing in this announcement should be construed as a profit forecast. Past share performance cannot be relied upon as a guide to future performance.

Chief Executive's report

All figures quoted are in US Dollars and relate to Business performance unless otherwise stated.

Overview

EnQuest is an expert in managing assets in mature basins. We do this by improving operational uptime, lowering costs and extending asset life. At the end of an asset's economic life, we either safely decommission it or repurpose it for a low carbon future.

Across the UK North Sea and South East Asia, we operate c.96% of our 2P reserves. This means we have strong control over how we deploy our people and capital. Our focus is to invest in maintenance and low-cost, fast-payback opportunities that diversify production, help manage natural field declines, lower costs and reduce emissions. We have been careful to enter these assets with financial agreements that minimise our exposure to decommissioning costs.

Delivering diversified growth is central to our strategy. In the UK North Sea, we remain focused on utilising our core operational skills and advantaged tax position to deliver a deal that propels us into the top tier of producers. This will expand the Group's cash flow, enabling us to boost shareholder distributions and accelerate our growth in South East Asia.

Since ending 2024, we have grown our cash and available facilities to $549.0 million as at 28 February 2025. This provides a strong foundation from which to transact, and we are focused on 2025 as a year of transformational delivery.

Market conditions

In 2024, wars in Ukraine and Gaza intensified and over 70 countries, representing more than half of the world's population, held national elections. Despite this complex geopolitical mix, oil prices were lower but relatively stable, with Brent averaging $80.5/bbl.

In the UK, the Labour Party entered power following the General Election with a strong majority and a manifesto pledge to tighten fiscal conditions in the UK North Sea, despite the UK being the only country in the world to maintain a windfall tax on oil and gas producers in 2024. The new government used its first Budget Statement to increase the Energy Profits Levy ('EPL') rate to 38% and extended its duration to 31 March 2030. This was the fifth material amendment to UK sector taxation in the last two and a half years. Such volatility undermines North Sea investment and impacts jobs and equipment that are essential to delivering the UK's transition ambitions.

As more industry participants accelerate their shift in focus away from the UK North Sea, we retain the view that a significant proportion of UK production is transactable, and we are clear in our desire to be a sector consolidator. Our significant tax loss position and the impact of the EPL on marginal tax rates means that the transfer of assets to EnQuest ownership would increase their relative value to a multiple of that in the hands of existing owners. The combination of this relative tax advantage and our differentiated operating capability, including demonstrable decommissioning expertise, make EnQuest the right operator to maximise the value of mature assets in the North Sea.

EnQuest has a track record of demonstrating resilience, creativity, and adaptability, and can generate opportunities in such circumstances. Having consistently delivered against production, operational and cost targets, we have generated material-free cash flows across recent years, even during periods of significantly reduced commodity prices.

This commitment to delivery, against the backdrop of a challenging UK fiscal environment, has seen us reduce EnQuest net debt by more than $1.6 billion since its peak. With no outstanding debt maturities until 2027, now is the time for EnQuest to build on that strong foundation as we look to deliver material growth in the UK and accelerate the value of our significant UK tax asset.

Exceptional operating performance

In 2024, EnQuest delivered production efficiency of c.90% across its operated portfolio, production averaging 40,736 Boepd (2023: 43,812 Boepd). 80% of this production originated from the UK North Sea and 88% of Group output was oil.

With 88% production efficiency, our North Sea assets again significantly exceeded the industry's average basin performance (c.77%). Given EnQuest's focus on late-life assets, this is a standout achievement.

The Kraken field continued to perform at the very top of the production efficiency for floating hubs, the FPSO's 95.5% production efficiency exceeding North Sea average efficiency by c.25%.

High levels of uptime at Magnus were offset by minor delays to the five-yearly rig recertification, which in turn delayed the start-up of several new wells. The field also suffered an outage on third-party infrastructure in the fourth quarter of 2024. To mitigate this, the Group designed and executed a well optimisation campaign that added over 1,000 Boepd of incremental production.

Production efficiency in Malaysia averaged 94% and production totalled 8,149 Boepd (10% up on 2023). This was underpinned by three new infill wells and strong domestic demand for associated Seligi 1a gas, for which EnQuest receives a handling and delivery fee.

EnQuest is successfully delivering against a key component of its strategy by delivering diversified growth, with successive South East Asian transactions, that provide geographic and commodity diversification within the portfolio. Our entry into Vietnam through the Block 12W acquisition and extending our Malaysian footprint with the expansion of our Seligi gas agreement and the DEWA PSC award are all underpinned by EnQuest's differentiated operating capability and our ability to deploy our expertise to create asset value. As EnQuest continues to work towards a transaction in the UK North Sea and further potential new country entries in South East Asia, these agreements underline our commitment to growth, a disciplined approach to M&A, and a strategy to deploy capital where we see the most favourable returns.

At the other end of the lifecycle of our asset portfolio, EnQuest plugged and abandoned ('P&A') another 22 wells, and the Group remains on track to complete well P&A work on both Heather and Thistle in 2025. Although we have delivered more than 35% of the total well P&A work in the North Sea over the last three years, our exposure to the cost of this work remains one of the lowest in the basin, as these costs have mostly been left behind with the original owners of the assets. We continue to deliver P&A activities at a per well cost that is significantly below the North Sea Transition Authority ('NSTA') industry benchmark, and in recognition of our decommissioning expertise, in 2024 Shell transferred to EnQuest its decommissioning management role of the Greater Kittiwake Area.

Having produced c.14 MMboe of hydrocarbons in 2024, we almost fully replaced these volumes through 2P reserve additions in South East Asia, with Group 2P reserves totalling 168.6 MMboe at 31 December 2024 (2023: 174.9 MMboe). 2C resources also remained robust, totalling c.354 MMboe, Bressay and Bentley each holding more than 100 MMboe of net resource.

Post the period end, EnQuest added a further 7.5 MMboe of 2P and reserves and 4.9 MMboe of 2C resource through the acquisition of Harbour's Vietnam operations.

Financial performance

The Group's continued solid financial and operating performance in the period drove further strengthening of EnQuest's balance sheet and enabled the focus of the business to pivot to shareholder distributions and growth.

We reduced our EnQuest net debt by a further $95.1 million, to $385.8 million (31 December 2023: $480.9 million) and we were delighted to execute our first shareholder return programme, repurchasing $9.0 million of capital via a share buyback.

Lower commodity prices, production and the Magnus crossover gas component reduced Group revenue to $1,180.7 million (2023: $1,487.4 million). The Magnus crossover gas also drove a reduction in cost of sales, with production costs flat year-on-year. Production costs were, however, flat year-on-year at $20.6/boe. Adjusted EBITDA fell by 18.5%, to $672.6 million (2023: $824.7 million) but EnQuest's effective tax rate fell to 43.7% (2023: 113.3%) due to the recognition of additional carried forward tax losses. As a result, the Group reported a post-tax profit of $93.8 million (2023: $30.8 million loss).

Capital expenditure in the period rose to $252.9 million, primarily relating to the Magnus five-yearly rig recertification, Golden Eagle drilling, decarbonisation projects at SVT, and the emission-reducing Magnus Flare Gas Recovery project (2023: $152.2 million). Decommissioning expenditure totaled $60.5 million (2023: $58.9 million). In the period, we also received repayment of a vendor loan that was provided to RockRose as part of the 2023 Bressay farm-down.

We used our financial strength to make $130.6 million of net repayments on our loans and borrowings (2023: $237.1 million), repaying our RBL facility in full ($140.0 million) in Q1 2024 and, in Q4 2024, repaying the entire $150.0 million term loan facility through a $160.0 million tap of EnQuest's high yield bond, which has simplified transaction-ready access to our RBL.

Following the RBL redetermination process at the end of 2024 and with no further drawdowns in the first quarter of 2025, $237.1 million of the RBL facility remains available to EnQuest for future drawdown.

We understand the importance of distributions to our shareholders and, having ended 2024 with a strong financial position, EnQuest is pleased to propose its maiden dividend, which for 2025 will be 0.616 pence per share, equivalent to c.$15 million.

Environmental, Social and Governance

Against the 2018 baseline established by the NSTA's North Sea Transition Deal, we have reduced our absolute UK Scope 1 and Scope 2 emissions by over 40%, providing a strong foundation for our commitment to reach net zero in Scope 1 and Scope 2 emissions by 2040.

Work continues to decarbonise existing portfolio infrastructure. Examples of these initiatives include the Magnus Flare Gas Recovery project, which was sanctioned in 2024, and development of the Bressay gas cap, for which we target regulatory approval later this year. At the Sullom Voe Terminal ('SVT') on Shetland, we are progressing two significant projects: the New Stabilisation Facility ('NSF') and the long-term power solution, which together will reduce SVT's carbon footprint by c.90%.

Under the management of Veri Energy, a wholly owned subsidiary of EnQuest, we are also supporting the UK's transition ambitions by progressing several scalable renewable energy and decarbonisation projects.

The health, safety and wellbeing of our employees remains our top priority. In 2024, our Lost Time Incident ('LTI') performance fell short of our expectations and was out of line with the Group's recent safety record. EnQuest aims to be in the upper quartile for safety performance and is working closely with all contractors to ensure that everyone working at our sites is aligned with EnQuest's commitment to SAFE results.

2024 saw a number of changes to the EnQuest Board, with Jonathan Copus, our Chief Financial Officer, formalising his Board position and Rosalind Kainyah MBE and Marianne Daryabegui joining the Board as Non-Executive Directors. With Salman Malik, Rani Koya and Liv Monica Stubholt stepping down as Directors at the Annual General Meeting ('AGM'), I would like to thank them for their diligent contributions to EnQuest over the years. I look forward to working with the refreshed Board as we execute our growth strategy.

2025 performance and outlook

In 2025 our focus is to maximise the value of our existing assets, while using our operating expertise and advantaged UK tax position to grow our business through acquisition. Success in these goals is expected to deliver a step-change in our operations, which will expand cash flow and enable us to boost shareholder distributions and accelerate our growth in South East Asia.

Group production to the end of February from the current portfolio, excluding Vietnam, was 43,037 Boepd, and net debt at 28 February 2025 equalled $371.7 million. At the same date, following the Group's year-end RBL redetermination, cash and available facilities had risen to $549.0 million.

Our full-year 2025 net production guidance of between 40,000 and 45,000 Boepd includes pro forma volumes from our Vietnam acquisition (due to complete during the second quarter of 2025) and the expected impact of drilling and well work at Magnus and PM8/Seligi.

Pro forma operating costs are expected to be c.$450.0 million, while capital expenditures are expected to be c.$190.0 million. Decommissioning expenditures are expected to total c.$60.0 million.

In 2025 we are working to advance several important projects toward Final Investment Decisions (‘FID’). Development of Bressay’s gas cap will lower Kraken costs and emissions, whist de-risking the pathway to development of significant oil volumes on the Bressay and Bentley fields (together c.250 MMboe MMboe of the Group’s 2C Resources).

Following encouraging testing, we also aim to progress the Kraken Enhanced Oil Recovery (‘EOR’) project to a FID within the next 12 months. Initial estimates suggest that this has potential to unlock 30 to 60 MMbbls gross of additional recoverable oil.

Our position as a top quartile operator, alongside our advantaged UK tax position, enhances our M&A credentials as a responsible owner and operator of existing assets and infrastructure as we transition to a lower-carbon energy system, offering our people long-term opportunities. We also believe that our core capabilities and top quartile operating performance can be replicated and deployed across other geographies as we continue to grow and diversify internationally.

Reflecting on 2024, I am proud of the resilience, adaptability, and commitment that have defined our performance. Despite a dynamic and volatile global energy landscape, EnQuest has delivered diversified growth, demonstrated operational excellence, and returned capital to our shareholders. Our employees remain the cornerstone of our success and, together, we recognise the responsibility we share in shaping the future of energy.

As we look to execute a transformative transaction in the UK, and further diversification of our portfolio, we will continue to be guided by a commitment to generating value for our shareholders.

Operational review

2024 saw the Group deliver 90% production efficiency across its operated portfolio. EnQuest is proud of its differentiated operating capability, with its foundation in late-life asset management expertise and expansion to include sector-leading decommissioning performance.

The Group is committed to optimising all of the assets we operate and has a strong track record in extending the life of mature oil and gas fields. We do this by applying focus to maintenance, key production equipment and through the high-quality execution of drilling and well intervention work.

We are also focused on the decarbonisation of our portfolio and have several projects in flight at Magnus, Kraken and the Sullom Voe Terminal (‘SVT’), aimed at significantly reducing the Group’s carbon footprint and delivering an improved long-term operating cost base. These components are key to ensuring our operations continue to thrive in an evolving regulatory environment.

All the skills outlined above are transferable across our business and can be deployed as we grow, in both the UK and in South East Asia, and as we right-size and repurpose existing infrastructure to create a decarbonisation and renewable energy hub at SVT.

In delivering production uptime of 90% across its operated portfolio during 2024, EnQuest achieved a level of performance which sits at the very top end of the UK North Sea sector.

The latest available benchmarked data from the North Sea Transition Authority (‘NSTA’) shows that production efficiency across the UKCS is 77%. EnQuest’s UK operated asset uptime was 88%.

Further, the NSTA UKCS production efficiency for floating hubs is 71%. At 95.5% production efficiency, EnQuest’s Kraken FPSO beats that by almost 25%.

This exemplary uptime performance extends to the Group’s South East Asia business, with 94% uptime at PM8/Seligi.

2024 UK operations performance summary

Production of 32,587 Boepd across EnQuest’s UK upstream assets was underpinned by strong production efficiencies across the portfolio and the Group’s investment in low-cost, quick-payback well work and production optimisation, partially offsetting the impact of natural field declines.

Kraken

2024 performance summary

The Kraken Floating, Production, Storage and Offloading (‘FPSO’) facility delivered an exceptional production efficiency of 96% (2023: 86%) and water injection efficiency of 95.5% (2023: 85%) for the year, resulting in average 2024 net production of 12,759 Boepd (2023: 13,580 Boepd). This is a testament to the focus and collaboration between the EnQuest and Bumi Armada operational teams, delivering production efficiency performance that is 24.5% above the industry average benchmark for floating hubs (as measured against the latest North Sea Transition Authority data).

The Kraken maintenance shutdown was completed in ten days (six days full shutdown and four days on single train operations). This work included the five-yearly FPSO swivel inspection.

The Group continues to optimise Kraken cargo sales through the shipping fuel market. Kraken oil is a key component of International Maritime Organization (‘IMO’) 2020 compliant low-sulphur fuel oil and, avoiding refining-related emissions.

2025 outlook

The asset team is focused on maintaining best-in-class FPSO production efficiency through focused investment in maintenance and reliability activities. Work is ongoing to mature the Kraken Enhanced Oil Recovery ('EOR') project to a Final Investment Decision ('FID') within the next 12 months. EOR represents a material upside to Kraken's value, with base case incremental recoverable oil estimates of 30 to 60 MMbbls gross.

The EnQuest team is advancing a gas import project that involves the subsea tie-back of a Bressay gas well to the Kraken FPSO. By establishing an alternative fuel supply to the diesel currently used to power Kraken operations, this project has the potential to drive a step change reduction in FPSO emissions and operating costs. It is anticipated that the Bressay gas well can be drilled as part of an expanded well programme, alongside the resumption of drilling at Kraken and a subsea well plugging and abandonment programme.

With c.33 MMboe of 2C resources, the Group remains well positioned to pursue infill drilling opportunities in the main Kraken field reservoir. Plans for these activities will be advanced in parallel with the EOR project. In 2025, Kraken production will be subject to natural field decline and the impact of a 15-day maintenance shutdown planned in the third quarter of the year.

Magnus

2024 performance summary

In 2024, Magnus celebrated 40 years of operations. Asset production efficiency was 83% (2023: 88%) and the annual maintenance shutdown was completed in 18 days (versus the original 21-day plan) with all major scopes executed. The shutdown involved 10,000 manhours of work being completed with zero lost-time incidents.

Production of 14,173 Boepd was 11% lower than 2023 (15,933 Boepd), due to a break in the infill drilling programme to accommodate the five-yearly rig recertification scope which was undertaken in the first half of the year, and incurred minor delays. Some of the planned well intervention also required rig remediation, which resulted in wells being offline for longer than originally planned. The Magnus team partially offset these losses through a successful gas lift optimisation campaign (which added incremental production of 1,000 Boepd) and through improving water injection sweep (which delivered a 2% reduction in overall Magnus field water cut through the year). In the fourth quarter, an unplanned outage of the Magnus subsea isolation valve within third-party-operated export infrastructure shut in all system users, including Magnus production. Production was reinstated within seven days following a collaborative response by all users with EnQuest operating the repair activities.

EnQuest remains focused on the efficient management of key Magnus topside infrastructure and targeted investment to optimise equipment reliability, reduce obsolescence and continue to deliver top quartile operational uptimes.

2025 outlook

The Group plans to execute an infill drilling programme and production-enhancing well intervention campaign at Magnus. The asset team is also focused on enhancing water injection and reservoir sweep, including progressing the conversion of a high water cut production well to water injection. This is expected to increase reservoir pressure and boost production. Looking beyond this programme of work, Magnus 2C resources of c.28 MMboe offer additional significant low-cost, quick-payback drilling and well intervention opportunities.

The Group plans a two-day production outage in the third quarter of 2025, aligned to a planned maintenance shutdown in third-party operated export infrastructure. The asset team is also progressing the Ninian bypass project towards FID in 2025. This involves the subsea bypass of the Ninian Central Platform which is planned for cessation of production in 2027. Alongside ongoing work at the Sullom Voe Terminal on the New Stabilisation Facility, this project will secure a long-term export pathway for Magnus oil.

Following the initiation of the Magnus Flare Gas Recovery project in Q4 2024, engineering work will continue in 2025. This project demonstrates EnQuest's commitment to the decarbonisation of its portfolio.

Greater Kittiwake Area

2024 performance summary

At the Greater Kittiwake Area ('GKA'), 2024 production averaged 2,009 Boepd (2023: 2,412 Boepd), largely in line with expectations. Solid operational performance in the year was underpinned by production efficiency of 77% (2023: 83%) and included the efficient completion of the planned maintenance shutdown.

2025 outlook

EnQuest and its partners are focused on extending field life and executing an efficient glide path to decommissioning, including plans for early plugging and abandonment of platform wells prior to cessation of production. This process will be managed in full by EnQuest, with Shell transferring its decommissioning operator role to EnQuest during 2024. A 14-day maintenance shutdown is planned at GKA during Q3 2025.

Non-operated North Sea assets

2024 performance summary

2024 production across the Group's non-operated UK interests averaged 3,646 Boepd (2023: 4,450 Boepd). The 2023/24 platform drilling programme at Golden Eagle concluded in August 2024. Two of the three planned producers were successfully brought online alongside the planned water injector, although overall production rates were below expectations.

At Alba, performance continued in line with the Group's expectations.

2025 outlook

At Golden Eagle, a 15-day shutdown is planned during the third quarter. The operator also plans to execute well intervention work in the form of mud acid stimulations in June.

At Alba, a more extensive shutdown of 28 days is planned.

2024 SOUTH EAST ASIA performance summary

PM8/Seligi, Malaysia

2024 performance summary

In 2024, EnQuest was awarded two accolades at the Malaysia Upstream Awards, including Operator of the Year and Excellence in HSE. To be recognised in this way by PETRONAS was extremely gratifying and is testament to the work undertaken across the EnQuest Malaysia team.

Malaysian production averaged 8,149 Boepd, 10% higher than 2023. This increase was driven by continued operational excellence and production efficiency of 94% (2023: 90%), benefitting from the availability of all compression units throughout the year. 2024 volumes include 1,978 Boepd associated with Seligi 1a gas, to which Petronas holds the entitlement, and EnQuest receives a gas handling and delivery fee.

The Group successfully executed a three-well infill drilling programme during 2024, with realised production rates in line with expectations. Three well workovers were also completed, and the Group continued work on the PM8/Seligi idle well restoration programme. Six wells were plugged and abandoned in accordance with the planned decommissioning programme. The 2024 shutdown was completed during the third quarter of 2024, with all critical integrity and maintenance works, including a turbine control panel upgrade, delivered on schedule.

EnQuest continued its excellent HSE performance in Malaysia during 2024, reaching the milestones of two years and 4.9 million man hours worked without a lost time incident.

2025 outlook

The Group plans to drill four infill wells during 2025, targeting undrained oil in step-out areas of the main reservoir and undeveloped minor reservoirs. The asset team is also targeting delivery of a well workover, with eight wells to be plugged and abandoned. The drilling rig and workover unit will mobilise during the first quarter of the year.

A two-week shutdown at PM8/Seligi to undertake asset integrity and maintenance activities is planned for the summer, which will help to improve reliability and efficiency at the field.

EnQuest has significant 2P reserves and 2C resources of c.36 MMboe and c.28 MMboe, respectively, with future multi-well annual drilling programmes planned. The Group continues to work with the regulator to assess the opportunity to develop the additional gas resource at PM8/Seligi to meet forecast Peninsular Malaysia demand.

Malaysia growth

Delivering portfolio diversification

Building on a decade of successful operations in Malaysia, EnQuest was awarded the DEWA Production Sharing Contract (‘PSC’) and will be operator of the block with largest participating interest of 42.0%.

The DEWA PSC consists of 12 discovered fields in an area c.50 kilometres off the coast of Sarawak, in water depths of 40 to 50 metres. The block is in a proven hydrocarbon area containing undeveloped discoveries, providing low-cost development options to provide gas supply into the Sarawak gas system.

Within the initial two-year pre-development term of the PSC, EnQuest and its partners will complete a resource assessment and submit a Field Development and Abandonment Plan for the cluster of fields, which could hold up to 500 Bscf of gas in place, with the potential to deliver production of c.100 mmscf per day (c.18 Kboed).

In addition, the Group was awarded an expansion to its Seligi gas agreement, with the award to develop an additional 155 Bscf (c.27 million barrels of oil equivalent) of non-associated Seligi field gas resources.

The agreement enables EnQuest and its partners to develop and commercialise the non-associated gas resources in the PM8E PSC contract area and, in line with expected demand, supply around 70 mmscf per day of sales gas. With a 50% equity share, this represents c.35 mmscf per day net to EnQuest, which equates to c.6,000 Boepd.

EnQuest will produce the additional gas by modifying its existing infrastructure, with low levels of development capex required to deliver new volumes into the Peninsular Malaysia gas system, helping the nation meet its increasing energy needs. With first gas from the project expected in 2026, these volumes will increase the gas component of EnQuest’s production, which aligns to the Group’s strategic aim to reduce its overall carbon intensity.

Delivering diversified growth – Vietnam new country entry

In January 2025, EnQuest signed a Sale and Purchase Agreement to acquire Harbour Energy’s business in Vietnam, which includes the 53.125% equity interest in the Chim Sáo and Dua production fields. This transaction aligns with the Group’s strategic aim to grow its international operating footprint by investing in fast-payback assets, with low capex and reduced carbon intensity.

The transaction has an effective date of 1 January 2024 and is scheduled to complete during the second quarter of 2025. The headline value of the transaction is $84 million and, net of interim period cash flows, the consideration to be paid by EnQuest on completion is expected to equal c.$35 million. This fully staffed new country entry expands the Group's South East Asian footprint beyond Malaysia, where EnQuest recently celebrated ten years of successful operations.

EnQuest will operate the Chim Sáo and Dua fields ('Block 12W') from completion, deploying its proven late-life and FPSO asset management expertise to maximise value and progress discovered resources into reserves.

Block 12W is made up of three producing oil and gas fields; Chim Sáo, Chim Sáo North West and Dua, located in the Nam Con Son Basin, approximately 400km south west of Vung Tau, Vietnam. As at 1 January 2025, net 2P reserves and 2C resources across the fields total 7.5 million Boe and 4.9 million Boe, respectively. Block 12W production has responded positively to the drilling of three infill wells during 2023 and a series of well interventions undertaken in 2023-2024, with the combined impact of these scopes contributing c.3.0 MMboe to 2P reserves at 1 January 2025.

Net production in 2025 is forecast to average c.5.3 kboepd, with further significant upside potential relating to well intervention performance. Oil (c. 73% of output) is high quality and has historically realised a c.10% premium to Brent. Gas is commercialised via an Associated Gas Gathering Agreement. Field volumes are produced at a life of field asset breakeven of c.$40 per Boe, with minimal capital requirements and a decommissioning liability that is covered via a PSC fund. The resulting free cash flow underpins Chim Sáo and Dua's value, making them strong anchor assets for EnQuest's entry into Vietnam.

The Block 12W Production Sharing Contract runs to November 2030, with an opportunity to extend the contract. Additional Block 12W prospectivity is spread across gas discoveries and several additional targets; potential upside that EnQuest intends to investigate.

As a country, Vietnam has significant potential for oil and gas development beyond its established 4.4 billion Boe reserves, with an increase in exploration in the hydrocarbon-rich South China Sea driving projects which seek to replace the production from mature offshore fields. In addition, there is significant opportunity for late-life asset managers, such as EnQuest, to acquire producing assets as established operators have PSCs nearing their end dates.

DECOMMISSIONING

Performance summary

For EnQuest's dedicated decommissioning team, 2024 represented another year of sector-leading delivery; further enhancing the Group's strong track record of executing multi-asset abandonment campaigns. With the majority of well plug and abandonment ('P&A') activity completed significantly faster and cheaper than sector averages, the Thistle and Heather project teams are focused on the culmination of the respective projects. Work is underway ahead of the 2025 preparation and removals programmes at these two major North Sea platforms.

Recognising EnQuest's ability to deliver SAFE Results, exemplary decommissioning performance and cost and schedule efficiencies, the Greater Kittiwake Area ('GKA') joint venture has appointed EnQuest as operator for the full GKA decommissioning scope, with Shell transferring its decommissioning management role to EnQuest. The GKA infrastructure is expected to continue production into the late 2020s, with EnQuest proactively planning for well P&A activity to be completed alongside asset production. This approach will result in a managed glidepath for the asset and will help EnQuest to optimise the post cessation of production decommissioning programme.

Well decommissioning

At both the Heather and Thistle fields, the extensive programme of well P&A continued at pace throughout the year. The Thistle team successfully abandoned 11 wells during 2024, with a further well nearing completion at year end. At Heather, 11 wells were completed by year end, resulting in the completion of all abandonment work to Phase 2 and the commencement of the final well decommissioning scope, Phase 3 conductor recovery.

In addition to the completion of 22 well abandonments across the two platform rigs, the Thistle project team continued to implement a third activity string, in the form of a conductor pulling unit ('CPU') to execute the recovery of conductors on available wells. This resulted in a further 17 wells being abandoned to the final stage of the well P&A process, taking Thistle to a total of 24 wells fully abandoned.

Both the Thistle and Heather project teams are targeting completion of their well P&A campaigns during 2025.

The Heather team aims to permanently disembark the platform in the second quarter of 2025, while Thistle is scheduled for disembarkation early in 2026. Both projects remain in line with the respective removals contract dates, with Heather topside removals commencing during 2025 and Thistle topside removals scheduled in 2026.

Throughout 2024, EnQuest has also progressed planning and engineering work on the subsea wells at Alma Galia, Dons and Broom, while continuing to discuss the future work programmes with the North Sea Transition Authority.

Preparation for removal

Alongside the completion of Phase 1 and Phase 2 abandonment work, the Heather project team successfully completed the flushing of the gas import and oil export pipelines, the cutting and laydown of the five Broom flexible risers and, through close collaboration with Allseas, ensured the safe execution of all platform preparatory works on Heather. This primarily involved the welding of necessary lifting points underdeck and separation of topsides pipework from the jacket to support future topsides removal.

The Heather team is fully focused on safe disembarkation of the asset, with the key scope being the completion of the topsides cleaning and utility rundown. This will be followed by the necessary leg-cutting works before the arrival of the Pioneering Spirit heavy lift vessel during the summer of 2025 to lift and remove the topsides and transport to Denmark for safe disposal.

At Thistle, the project team continued to demonstrate its capability to deliver multiple key scopes simultaneously. EnQuest and Saipem teams have worked closely together, progressing engineering and planning for the nine-month pre-disembarkation preparation phase in 2025 and the future topside and jacket heavy lift campaigns. An extensive module void inspection campaign was successfully completed which involved accessing, inspecting and clearing 43 void spaces. Subsea campaigns were also completed covering essential inspection, repair and maintenance activities and preparatory work for future conductor removal activities using bespoke tooling developed with the subsea contractor.

Underdeck scaffold removal and key topside modifications were all completed efficiently and on schedule.

2025 marks the final full year on the platform, with disembarkation planned for early 2026. Key milestones for the year focus on completion of the main rig and conductor pulling units campaigns, completion of topside steam cleaning and pipeline flushing activities, and commencing and completing the removal preparations prior to disembarkation.

Asset removals

With significant Engineering, Preparation, Removal and Disposal (‘EPRD’) contracts in place for both Heather and Thistle, planning, engineering and preparatory works have been executed at pace during 2024.

2025 will see the culmination of significant work through the removal of the Heather topsides from field by Allseas and their Pioneering Spirit heavy lift vessel. The Heather jacket is scheduled for removal in 2027, which aligns with our agreed contractual execution windows.

MIDSTREAM

Safe, stable operations

Throughout 2024, the Group continued to deliver safe, stable and effective operations for both East of Shetland and West of Shetland oil and gas, delivering 100% uptime for both oil streams, and 100% uptime for West of Shetland gas. In addition, the SVT power station achieved 100% power delivery throughout the period. The terminal continued to deliver strong HSE performance, effectively managing the increase in project personnel on-site throughout the year. During 2024, the milestones of five years, and five million work hours Lost Time Incident (‘LTI’) free were reached, underlining EnQuest’s commitment to safety. A subsequent LTI at the terminal enabled the team to review the circumstance and to ensure that mitigations and lessons learned were incorporated into reinforcing the HSE Management System.

Decarbonisation

The Group is focused on right-sizing SVT for future operations. During 2024, EnQuest successfully commenced Engineering, Procurement and Construction on two strategic projects: to connect the terminal to the UK’s electricity grid and the construction of New Stabilisation Facilities (‘NSF’). Completion of the NSF is expected to enable the Group to meet the North Sea Transition Authority (‘NSTA’) target of zero routine flaring obligations by 2030, while the aggregated impact of these two projects is expected to transform the carbon footprint and overall emissions from SVT and the EQUANS-operated Sullom Voe power station. The delivery of these scopes will reduce the Terminal’s operating costs and provide resilience for long-term operations through the replacement of obsolete equipment. Together, these projects provide the opportunity to extend production at both East of Shetland and West of Shetland assets.

In 2024, EnQuest commenced the phased, partial decommissioning of redundant processing and storage facilities at SVT. This scope has reduced the risk potential at the site, along with reducing ongoing operating costs. Furthermore, the removal of the facilities creates the opportunity to repurpose areas of SVT for third-party use, including renewable energy projects.

2024 emissions at SVT were elevated due to issues encountered with the site’s gas compression system, which resulted in flaring above the routine baseline levels. In September, an engineering solution was deployed effectively, restoring the compression system to full operations. This has resulted in a return to lower process flaring and emissions.

People and community

EnQuest continues to build its community investment on Shetland with contributions to local charities and sports groups, and through its workforce development programmes.

The Group has a well-established apprentice programme at SVT, with three apprentices successfully graduating in 2024. The Group also continued with its graduate programme in 2024, with one graduate recruited into SVT.

SVT supported a range of cultural and sporting events on Shetland in 2024, including Shetland Rugby’s mid-summer event for children, women and men’s matches, the Shetland Junior Golf Open and sponsorship of local table tennis events.

EnQuest also sponsored a Sail Training Shetland event for 70 young people from Shetland to Bergen and provided support to the Shetland Folk Festival.

Seven educational awards for the academic year 2023-2024 were made by the Trustees of the Sullom Voe Terminal Participants’ Tenth Anniversary Fund. Now in its 36th year, the Trust was established to promote and encourage the education of Shetland residents who will be studying a discipline likely to contribute to the social or economic development of Shetland. This year, students are engaged in disciplines as wide-ranging as medicine, primary education, folk and traditional music, geography and sustainable development. As terminal operator, EnQuest also offers a scholarship to a student studying in a technical or commercial discipline that is relevant to SVT, where they take part in a work placement at the terminal during the summer break.

VERI ENERGY

Veri Energy is a wholly owned subsidiary of EnQuest, focused on transforming skills and infrastructure to deliver economic decarbonisation solutions, initially at the Sullom Voe Terminal ('SVT') on Shetland. Veri Energy is supporting the UK Government's Clean Power 2030 Action Plan and delivering against the Scottish Government's Energy Strategy and Just Transition Plan.

Veri Energy is fuelling the UK's energy transition

Using the SVT site as a base, Veri Energy is looking to support further industrial decarbonisation and future growth in the energy transition through the execution of phased renewable energy developments.

Carbon capture and storage ('CCS')

Veri Energy continues to develop a flexible, merchant-market carbon storage solution that can transport and permanently store up to 10mtpa of CO_2 from isolated emitters in the UK and Europe. CO_2 captured by emitters will be transported via ship to SVT from where it will be transported, via repurposed pipeline infrastructure, for permanent geological storage in depleted oil and gas reservoirs.

In August 2023, EnQuest successfully secured four carbon storage licences as part of the first round of UK carbon sequestration licences issued by the North Sea Transition Authority ('NSTA'). Following work to assess the licences, EnQuest took the decision to relinquish the Tern and Eider licences, effective 1 March 2025. The remaining licence areas, CS013 and CS014, are some 99 miles northeast of Shetland and incorporate fields currently operated by EnQuest, the Magnus and Thistle fields. These sites are large, well-characterised deep storage formations connected by significant existing infrastructure to the Sullom Voe Terminal on Shetland.

During 2024, work included significant engagement with the NSTA to progress the licences through the early risk assessment phase, engaging with strategic partners and refining the project development plan. Veri Energy continues to be encouraged by the project's potential to be a low-cost merchant-market solution for CO_2 emitters to permanently sequester carbon beginning in the late 2020s/early 2030s.

Electrification

During 2024, Veri Energy identified an opportunity to develop an onshore wind power project to assist in decarbonising and reducing costs at the Sullom Voe Terminal, harnessing Shetland's natural advantage of one of the world's highest wind capacity factors and existing terminal infrastructure. The project underwent technical analysis, environmental impact assessment, and feasibility studies during 2024, and is expected to enter front-end engineering and design during 2025.

E-Fuels

Veri Energy continues to evaluate a multi-stage green hydrogen and derivatives project at Sullom Voe. During 2024, Veri received an award of £1.74 million in grant funding from the UK government's Net Zero Hydrogen Fund ('NZHF') to support a front-end engineering and design study for the project. The company continues to evaluate scenarios for end products, scale, partnerships and technology integration for the project.

The favourable conditions for development of net-zero e-fuels at SVT, via the combination of green hydrogen and biogenic CO_2, place Veri Energy at the forefront of plans to produce e-diesel that can displace demand for fossil fuels from the local marine and power industry. Powered by a skilled local workforce and supported by the advantaged conditions at the terminal site, there is the potential to scale this business for e-fuel export.

Financial review

Introduction

EnQuest delivered significant progress against each of its financial priorities in 2024, and this momentum has continued into 2025. The Group has optimised its capital structure and maximised available financial capacity for value-accretive growth, by successfully tapping its high yield bond and the repayment in full of both the reserve based lending ('RBL') and term loan facilities.

EnQuest net debt was reduced by $95.1 million, to $385.8 million. This reflects robust free cash flow generation, cash received from the farm-down of Bressay and returns to shareholders through the share buy-back programme.

EnQuest maintained a strong focus on disciplined and efficient capital expenditure and cost control. The investment in the future decarbonisation of Magnus through the installation of a flare gas recovery system reflects our focus on fast payback projects, while the re-certification of the Magnus platform drilling rig underpins ongoing low-cost drilling and well intervention work. As anticipated, EnQuest's increased share of throughput at the Sullom Voe Terminal ('SVT') led to higher tariff costs in the period, noting future cost and emission reductions are expected at the completion of the ongoing decarbonisation projects at the terminal.

In line with the Group's growth strategy, EnQuest signed several agreements in South East Asia: entering Vietnam through the acquisition of Block 12W; extending the Group's Malaysian footprint with the expansion of the Seligi gas agreement; and award of the DEWA PSC. These transactions provide geographic and commodity diversification, adding production and reserves.

The Group reported an IFRS post-tax profit of $93.8 million for the year to 31 December 2024 (2023: IFRS post-tax loss of $30.8 million). This was primarily driven by a lower tax charge in the period (reflecting fast payback investment and the recognition of an additional deferred tax asset associated with ring-fence expenditure supplement in the UK) offset by lower profit before tax (production was lower year-on-year and tariffs were higher).

EnQuest's year-end RBL redetermination expanded the leverageable capacity of the Group's assets, and at 28 February 2025 total cash and available facilities totalled $549.0 million (31 December 2023: $498.8 million). With the UK Autumn Budget Statement (30 October 2024) bringing clarity on the fiscal landscape of the UK North Sea, EnQuest's strategic UK tax advantage and financial capacity mean the Group remains well placed to pursue further growth opportunities in the North Sea and internationally. EnQuest's Board is also proposing a final dividend of 0.616 pence per share, equivalent to c.$15 million.

Income statement

Revenue

Group production averaged 40,736 Boepd (7.0% lower than in 2023, 43,812 Boepd), with strong uptime performance of c.90% across the operated portfolio and investment in low-cost, quick-payback well work and production optimisation partially offsetting the impact of natural field declines across the portfolio. Oil accounted for 87.2% of this output (2023: 90.0%).

Brent crude oil prices declined 2.4% year-on-year to average $80.5/bbl (2023: $82.5/bbl) while the average day-ahead UK gas price decreased by 15.5% to 83.6 GBp/therm (2023: 98.9 GBp/therm). Excluding the impact of hedging, EnQuest realised an average oil price of $81.3/bbl (2023: $82.2/bbl). Post-hedging, the realised oil price was $80.2/bbl (1.5% lower than in 2023, $81.4/bbl).

Reflecting the above price and volume drivers, Group revenue in the period totalled $1,180.7 million, a 20.6% reduction year-on-year (2023: $1,487.4 million). In this figure, oil contributed $1,020.3 million (9.5% lower year-on-year, 2023: $1,127.4 million) and condensate and gas revenue contributed $164.6 million (51.4% lower year-on-year, 2023: $339.0 million). Gas revenue mainly relates to the onward sale of gas purchases from third-party West of Shetland fields under the terms of the Magnus acquisition. The contribution of these volumes to revenue is therefore offset through an equal and opposite charge to cost of sales.

Tariffs and other income generated $2.6 million (2023: $1.3 million), which includes income associated with the transportation of Seligi gas. Realised losses on commodity hedges totalled $12.9 million, primarily reflecting the cost of historic put options (2023: $11.3 million). Unrealised gains on open commodity contracts (from mark-to-market movements) totalled $3.1 million (2023: $28.5 million).

Note: For the reconciliation of realised oil prices see 'Glossary – Non-GAAP measures' starting on page 70

Cost of sales

Cost of sales was $787.4 million which was 16.8% lower than in 2023 ($946.8 million).

Production costs were broadly flat, totalling $307.6 million ($20.6/Boe) but operating costs increased by $35.6 million to $382.8 million. This rise was as expected and reflected an increase to EnQuest's share of throughput at SVT. Costs and emissions at the terminal are forecast to reduce on completion of the current decarbonisation projects on site. With the combination of higher tariffs and lower production volumes, unit operating costs (excluding hedging losses) increased by 15.5% to $25.3/Boe (2023: $21.9/Boe).

	2024 $ million	2023 $ million
Production costs	**307.6**	308.3
Tariff and transportation expenses	**70.5**	41.7
Realised loss/(gain) on derivatives related to operating costs	**4.7**	(2.8)
Operating costs[1]	**382.8**	347.2
Charge/(credit) relating to the Group's lifting position and inventory	**2.2**	(4.2)
Other cost of operations	**136.3**	305.9
Depletion of oil and gas assets	**263.3**	292.2
Other cost of sales	**2.8**	5.7
Cost of sales	**787.4**	946.8
Unit operating cost[2,3]	**$/Boe**	$/Boe
– Production costs	**20.6**	19.3
– Tariff and transportation expenses	**4.7**	2.6
Average unit operating cost	**25.3**	21.9

Notes:
1 See reconciliation of alternative performance measures within the 'Glossary – Non-GAAP measures' starting on page 70
2 Calculated using production on a working interest basis including Seligi Associated Gas
3 Excludes realised loss/(gain) on derivatives related to operating costs

The charge relating to the Group's lifting position and hydrocarbon inventory for the year ended 31 December 2024 was $2.2 million (2023: credit of $4.2 million), with the Group in a net neutral lifting position across its asset base at 31 December 2024 (2023: net underlift position $3.5 million).

The cost of Magnus third-party gas purchases that are sold on is reported within 'other cost of operations'. These costs fell significantly to $125.7 million (2023: $294.0 million), due to reduced third-party volumes and lower gas prices.

Depletion expense ($263.3 million) was 9.9% lower than 2023 ($292.2 million), mainly reflecting lower production.

Impairment

In the year, the Group recognised a non-cash net impairment charge of $71.4 million (2023: $117.4 million). This charge reflected changes to the UK Energy Profits Levy confirmed by the UK Government in its Autumn Budget (including the planned two-year extension to 31 March 2030), lower short-term oil price assumptions and changes to the production profile of the non-operated Golden Eagle field, partially offset by production profile changes at the GKA hub and a lower discount rate of 10.0% (2023: 11.0%).

Other income and expenses

The Group has recognised net other expense in the period of $4.7 million (2023: net other expense of $19.6 million). The impact of both the unwind of discount and other changes in fair value of Magnus contingent consideration have been combined in other income and expenses following a review of market practice. This required a $58.9 million charge for 2023 being reclassed from finance costs. As such, 2024 incurred a net $15.9 million non-cash charge driven by: the unwinding of discounting offset by changes in the near-term oil price assumptions and production and cost profiles (2023: $10.8 million non-cash income, driven by an increase in the discount rate applied offset by the unwinding of discounting). Other items of other income and expense include: $14.6 million charge relating to the termination of a drilling rig contract following the Kraken joint venture's decision to defer near-term infill drilling; a non-cash charge of $7.1 million due to a net increase in the decommissioning provision of fully impaired non-producing assets (2023: non-cash charge of $32.8 million); a foreign exchange gain of $10.0 million, reflecting a favourable movement in the Sterling to US Dollar exchange rate (2023: $11.8 million foreign exchange losses); and lease income of $16.5 million (2023: $12.1 million).

Other expenses also include costs associated with Veri Energy, which totalled $1.7 million in the year (2023: $1.6 million).

Adjusted EBITDA

Adjusted EBITDA for the year totalled $672.6 million, down 18.4% compared to the same period in 2023 ($824.7 million). This reduction reflects the lower revenue associated with reduced production, as well as higher tariffs at SVT (see detail above).

EnQuest's net debt to last 12-month adjusted EBITDA ratio at 31 December 2024 equalled 0.6x. This was in line with the prior year (31 December 2023: 0.6x).

Adjusted EBITDA	**2024 $ million**	2023 $ million
Profit/(loss) from operations before tax and finance income/(costs)	**311.5**	397.4
Unrealised commodity hedge gain	**(3.1)**	(28.5)
Depletion and depreciation	**269.3**	298.3
Impairment charge	**71.4**	117.4
Net other expenses	**36.2**	25.1
Foreign exchange and UKA forward purchase losses	**2.8**	3.8
Change in well inventories	**(5.5)**	(0.6)
Net foreign exchange (gain)/loss	**(10.0)**	11.8
Adjusted EBITDA[1]	**672.6**	824.7

Note:
1 See reconciliation of Adjusted EBITDA within the 'Glossary – Non-GAAP measures' starting on page 70

Finance costs

EnQuest's overall net finance costs fell by 12.5%, to $144.9 million (2023: $165.6 million). This reflected a significantly lower level of outstanding loans and borrowings, resulting in a lower overall interest charge of $73.5 million (2023: $89.7 million). Partially offsetting this were higher refinancing fees (2024: $19.3 million), including the accelerated amortisation of remaining initial term loan fees of $2.9 million and the early redemption fee of $4.7 million paid following the repayment in full of the term loan in October 2024 (2023: $7.9 million).

Finance charges included the unwinding of discounting on decommissioning and other provisions (2024: $31.2 million; 2023: $25.4 million). Lease liability interest costs totalled $27.7 million (2023: $43.8 million), and there were other interest and financial expenses of $7.8 million (2023: $5.3 million), which primarily are the cost for surety bonds that provide security for decommissioning liabilities.

Finance income increased to $14.5 million reflecting additional cash on deposit and accrued interest on the RockRose vendor loan (2023: $6.5 million).

Profit/loss before tax

Reflecting the movements above, the Group's profit before tax was $166.6 million (2023: profit of $231.8 million).

Taxation

The 2024 tax charge of $72.8 million includes a current tax charge of $12.1 million (2023: $262.6 million, inclusive of a current tax charge of $185.6 million).

In the Autumn Statement on 30 October 2024, the UK government confirmed that from 1 November 2024 the rate of the Energy Profits Levy ('EPL') would be increased from 35% to 38%. It was also announced that EPL Investment Allowances would be abolished from 1 November 2024 and that decarbonisation relief would be retained but the rate of relief would be reduced from 80% to 66%. These changes increase the current year tax charge and deferred tax for EPL by $42.2 million. The announcement to extend the EPL period to 31 March 2030 was however not substantively enacted until March 2025, which resulted in there being no impact on the 31 December 2024 balance sheet. Had the extension been enacted, the Group estimates an additional deferred tax liability of $115.9 million would have been recognised (see note 6 for further information).

The Group's effective tax rate for the period was a charge of 43.7% (2023: 113.3%).

EnQuest's strategic UK North Sea tax asset was estimated at $2,066.4 (gross) million at 31 December 2024 (31 December 2023: $2,007.9 million (gross)). The increase reflects the recognition of additional carried forward losses associated with the ring-fenced expenditure supplement, partially offset by utilisation against the Group's profits before tax.

Due to this tax position, no significant corporation tax or supplementary charge is expected to be paid on UK operational activities for the foreseeable future. The Group expects to continue to make EPL payments for the duration of the levy, and EnQuest also pays cash corporate income tax on its Malaysian assets.

Profit/loss for the period

EnQuest's total profit after tax was $93.8 million, which compares to a 2023 loss of $30.8 million.

Earnings per share

The Group's reported basic earnings per share was 5.0 cents (2023 loss per share: 1.6 cents) and reported diluted earnings per share was 4.9 cents (2023 loss per share: 1.6 cents).

Cash flow, EnQuest net debt and liquidity

Driven by continued adjusted free cash flow generation in 2024 and the repayment of a vendor loan provided to RockRose related to the 2023 Bressay transaction, EnQuest net debt at 31 December 2024 totalled $385.8 million. This was $95.1 million lower than the position reported at 31 December 2023 ($480.9 million).

The movement in EnQuest net debt was as follows:

	$ million
EnQuest net debt 1 January 2024	(480.9)
Net cash flows from operating activities	508.8
Cash capital expenditure	(252.9)
Magnus profit share payments	(48.5)
Net interest and finance costs paid	(73.1)
Finance lease payments	(130.1)
Repayment of vendor loan provided to RockRose	107.5
Share buyback	(9.0)
Term loan early termination fee	(4.7)
Other movements, primarily net foreign exchange on cash and debt	(2.9)
EnQuest net debt 31 December 2024[1]	**(385.8)**

Note:
1 See reconciliation of alternative performance measures within the 'Glossary – Non-GAAP measures' starting on page 70

Reported net cash flows from operating activities for the year were $508.8 million. This was 32.5% below the comparative period of 2023 ($754.2 million). This reduction reflects: higher cash tax payments totalling $97.3 million (2023: $41.0 million, including a tax refund of $37.4 million); $17.7 million unwind of the joint venture advance cash call received in 2023 ($39.5 million); one-off payments relating to the rig cancellation ($14.6 million) and $8.5 million of funds released from escrow pending resolution of the final arbitration decision in relation to a dispute with a third party supplier in Malaysia; and lower gross profit, reflecting lower revenues and higher operating costs. Clean of one-off impacts of the tax refund, joint venture advance cash call movements, rig cancellation and contractor dispute payments, year-on-year cash flow from operating activities was 18.9% lower.

Reported net cash flows used in investing activities decreased year-on-year by $79.1 million, to $183.6 million (2023: $262.7 million). This principally reflects: higher capital expenditures ($252.9 million – primarily related to the Magnus five-yearly rig recertification work scope, Golden Eagle well campaign, decarbonisation projects at SVT, and the emissions reducing flare gas recovery project on Magnus (2023: $152.2 million)); offset by repayment of a vendor loan provided to RockRose ($107.5 million; 2023: net nil cash flow impact reflecting farm-down proceeds being offset by the vendor financing facilities from EnQuest to RockRose (see note 18); the final Golden Eagle acquisition costs paid in 2023 ($50.0 million); and lower Magnus profit share payments (2024: $48.5 million; 2023: $65.5 million).

Cash outflow on capital expenditure is set out in the table below:

Capital expenditure	**2024 $ million**	2023 $ million
North Sea	**230.4**	124.2
Malaysia	**19.0**	21.0
Exploration and evaluation	**3.5**	7.0
	252.9	152.2

The Group utilised $352.9 million of cash in financing activities (2023: $478.6 million). This included further net repayments of the Group's loans and borrowings totalling $130.6 million (2023: $237.1 million), with EnQuest repaying its RBL facility in full ($140 million) in the first quarter and, in the fourth quarter, the entire $150.0 million term loan facility following the successful conclusion of a $160.0 million tap of its high yield bond in October. Following the RBL redetermination process at the end of 2024 and no further drawdowns in the first quarter of 2025, $237.1 million of the RBL facility remains available to EnQuest for future drawdown.

Interest costs on the Group's borrowings totalled $83.2 million (2023: $105.9 million) and an additional $130.1 million was paid in relation to finance leases (2023: $135.7 million).

EnQuest also repurchased $9.0 million of shares as part of its share buyback programme.

In aggregate, the Group's cash and cash equivalents decreased by $33.4 million in 2024. This decrease was primarily driven by the repayment in full of the Group's RBL facility and share repurchases made under EnQuest's share buyback programme offset by the net cash inflow from the farm-down of Bressay and adjusted free cash flow generation. Adjusted free cash flow generation in 2024 was lower than in 2023, reflecting lower revenues, higher capital expenditure, partial unwind of the joint venture advance cash call received in 2023 and one-off costs associated with the drilling rig cancellation and the dispute with a third party supplier in Malaysia, partially offset by lower finance charges.

EnQuest net debt	**31 December 2024 $ million**	31 December 2023 $ million
Bonds	**632.1**	474.7
Senior secured debt facility ('RBL')	**–**	140.0
Term loan	**–**	150.0
SVT Working Capital Facility	**33.9**	29.8
Cash and cash equivalents	**(280.2)**	(313.6)
EnQuest net debt[1]	**385.8**	480.9

Note:
1 See reconciliation of EnQuest net debt within the 'Glossary – Non-GAAP measures' starting on page 70

The Group ended the year with $280.2 million of cash and cash equivalents (31 December 2023: $313.6 million) and cash and available undrawn facilities of $474.5 million (31 December 2023: $498.8 million). Subsequently, following the most recent RBL redetermination process, EnQuest's cash and available facilities have increased to $549.0 million at 28 February 2025.

Balance sheet

EnQuest's robust liquidity position enables the Group to continue delivering its capital-efficient programmes of capital investment and pursue transformational North Sea and International production acquisitions.

Assets

Total assets reduced by 5.4% to $3,562.6 million (31 December 2023: $3,765.8 million). Driving this were: Repayment of a vendor loan provided to RockRose ($107.5 million); a reduction of $33.6 million in the Group's deferred tax asset; and lower cash and cash equivalents of $33.3 million.

Liabilities

Total liabilities reduced by 8.7% to $3,020.1 million (31 December 2023: $3,309.0 million) reflecting continuing material debt repayments and optimisation of the capital structure (the full outstanding principals of $140.0 million on the RBL and $150.0 million for the term loan Facility were repaid in the year, offset by an additional $160.0 million tap of the high yield bond); lower tax liabilities, reflecting fiscally efficient investments and cash tax payments in the period, and a reduction in lease liabilities of $86.9 million. Deferred tax liabilities increased by $27.1 million.

Contingent consideration payments in the period (related to the acquisition of Magnus) totalled $48.5 million (2023: Magnus and Golden Eagle: $115.5 million). When combined with the net change in the fair value estimate, this payment drove a lower outstanding contingent consideration estimate of $473.3 million (31 December 2023: $507.8 million).

Financial risk management

The Group's activities expose it to various financial risks, particularly those associated with fluctuations in oil price, foreign currency risk, liquidity risk and credit risk. The disclosures in relation to financial risk management objectives and policies, including the policy for hedging, and the disclosures in relation to exposure to oil price, foreign currency and credit and liquidity risk, are included in note 27 of the Group's 2024 Annual Report.

Going concern disclosure

In recent years, EnQuest has focused on deleveraging and optimising its capital structure, to simplify its balance sheet and maximise available financial transactional capacity.

In 2024, the Group deleveraged further, reducing net debt by $95.1 million, to $385.8 million at 31 December 2024. This was driven by robust adjusted free cash flow generation and repayment of the first of two vendor loans that was provided to RockRose as part of the 2023 Bressay farm-down. In the period EnQuest fully repaid its Reserve Based Lending ('RBL') facility (from $140.0 million) and completed a $160.0 million tap of its high yield bonds. By using this tap to repay a $150.0 million term loan facility, additional RBL capacity was opened. At 31 December 2024, EnQuest's net debt to adjusted EBITDA ratio was 0.6x. The Group ended 2024 with a positive RBL redetermination, which expanded RBL capacity by 34%. Cash and available facilities at 28 February 2025 totalled $549.0 million.

Against this robust backdrop, EnQuest continues to closely monitor and manage its funding position and liquidity requirements throughout the year, including monitoring forecast covenant results. Cash forecasts are regularly produced and sensitivities considered for, but not limited to, changes in crude oil prices (adjusted for hedging undertaken by the Group), production rates and costs. These forecasts and sensitivity analyses allow management to mitigate liquidity or covenant compliance risks in a timely manner.

The Group's latest approved business plan underpins management's base case ('Base Case'). It is in line with EnQuest's production guidance (including the acquisition and contribution of the Block 12W in Vietnam – completion expected in the second quarter of 2025) and an oil price assumption of $75.0/bbl is used for 2025 and 2026.

A reverse stress test has been performed on the Base Case. This indicates that an oil price of c.$40.0/bbl is required to maintain covenant compliance over the going concern period. The low level of this required price reflects the Group's strong liquidity position.

The Base Case has also been subjected to further testing through a scenario that explores the impact of the following plausible downside risks (the 'Downside Case'):

- 10.0% discount to Base Case prices resulting in Downside Case prices of $67.50/bbl for 2025 and 2026;
- Production risking of 5.0%; and
- 2.5% increase in operating costs.

The Base Case and Downside Case indicate that the Group is able to operate as a going concern and remain covenant compliant for 12 months from the date of publication of its full-year results.

After making appropriate enquiries and assessing the progress against the forecast, the Directors have a reasonable expectation that the Group will continue in operation and meet its commitments as they fall due over the going concern period. Accordingly, the Directors continue to adopt the going concern basis in preparing these financial statements.

Viability statement

The Directors have assessed the viability of the Group over a three-year period to March 2028. The viability assumptions are consistent with the going concern assessment, with the extension of an oil price of $75.0/bbl for 2027 and 2028 in the Base Case. Consistent plausible downside risks have also been applied in a Downside Case. This assessment has taken into account the Group's financial position as at 26 March 2025, its future projections – including the impacts of the Block 12W acquisition in Vietnam; the Seligi 1b gas agreement; the Group's debt maturities, which occur towards the end of the viability period; and the Group's principal risks and uncertainties. The Directors' approach to risk management, their assessment of the Group's principal risks and uncertainties, and the actions management are taking to mitigate these risks, are outlined on pages 19 to 30. These risks and uncertainties include potential impacts from climate change concerns and related regulatory developments. The period of three years is deemed appropriate as it is the time horizon across which management constructs a detailed plan against which business performance is measured, and, given the Group's focus on short-cycle, quick payback capital expenditures on its existing portfolio, is a time horizon over which the Group can undertake any necessary mitigation activities.

Under the Group's Base Case projections, the Directors have a reasonable expectation that the Group can continue in operation and meet its liabilities as they fall due over the period to March 2028.

For the current assessment, the Directors also draw attention to the specific principal risks and uncertainties (and mitigants) identified below, which, individually or collectively, could have a material impact on the Group's viability during the period of review. In forming this view, it is recognised that such future assessments are subject to a level of uncertainty that increases with time and, therefore, future outcomes cannot be guaranteed or predicted with certainty. The impact of these risks and uncertainties has been reviewed on both an individual and combined basis by the Directors, while considering the effectiveness and achievability of potential mitigating actions.

Oil price volatility

A decline in oil prices would adversely affect the Group's operations and financial condition. To mitigate oil price volatility, the Directors have hedged a total of 3.1 MMbbls from 1st April 2025 for the next 12 months with an average floor price of $69.6/bbl and a further 1.3 MMbbls in the subsequent 12 month period with an average floor price of $68.3/bbl, in each case predominantly utilising swaps. The Directors, in line with Group policy and the terms of its RBL facility, will continue to pursue hedging at the appropriate time and price.

Fiscal risk and government take

Unanticipated changes in the regulatory or fiscal environment, such as the UK EPL in recent years, can affect the Group's ability to access funding and liquidity. The Group will continue to communicate to Government and Treasury the importance of fiscal stability, whilst also monitoring developments and any potential related impacts.

Access to funding

Prolonged low oil prices, cost increases, production delays or outages and changes to the fiscal environment could threaten the Group's liquidity and access to funding.

The Directors recognise the importance of ensuring medium-term liquidity. The Group has evidenced its continued management of funding, prioritisation of debt reduction and optimisation of its capital structure by fully repaying its RBL and Term Loan along with obtaining additional unsecured funds through a successful high yield bond tap in 2024. The increase in available funds under the RBL following the recent redetermination and the long-dated maturity profile of the Group's debt provide a material level of funding for the majority of the viability period. Refinancing of the Group's current debt structure (see note 17) is assumed towards the end of the viability period but would likely occur well ahead of the 2027 bond maturities, providing funding beyond the viability period.

In assessing viability, the Directors recognise that in a Downside Case additional liquidity would be required towards the end of the viability period, which may necessitate limited mitigations, such as working capital management, amendments to capital work programmes, asset farm-downs or other financing options, including vendor financing or prepayments. Given the extended duration of the viability period, the Directors believe such measures can be executed successfully in the necessary timeframe to maintain liquidity.

Notwithstanding the principal risks and uncertainties described above, after making enquiries and assessing the progress against the forecast, projections and the status of the mitigating actions referred to above, the Directors have a reasonable expectation that the Group can continue in operation and meet its commitments as they fall due over the viability period ending March 2028. Accordingly, the Directors therefore support this viability statement.

EnQuest oil and gas reserves and resources

	North Sea			South East Asia			Total		
	Oil and NGLs MMbbls	Gas Bcf	Total MMboe	Oil and NGLs MMbbls	Gas Bcf	Total MMboe	Oil and NGLs MMbbls	Gas Bcf	Total MMboe
2P reserves (working interest)1,2,3,5,6									
1 January 2024	135.2	65.5	146.5	25.4	16.9	28.4	160.7	82.3	174.9
Revisions[4]	(1.0)	(7.1)	(2.2)	(3.4)	77.5	10.0	(4.3)	70.4	7.8
Production	(11.0)	(5.2)	(11.9)	(2.0)	(0.6)	(2.1)	(13.0)	(5.8)	(14.0)
31 December 2024	123.3	53.1	132.4	20.1	93.8	36.3	143.3	146.9	168.6
2C resources (working interest)1,2,7,8									
1 January 2024	305.1	18.1	308.2	31.1	287	80.6	336.2	305.1	388.8
Revisions, additions and relinquishments	0	0	0	(13.3)	(126.8)	(35.2)	(13.3)	(126.8)	(35.2)
31 December 2024	305.1	18.1	308.2	17.8	160.2	45.4	322.9	178.3	353.6

Notes:
1 Reserves and resources are quoted on a working interest basis
2 2P reserves and 2C resources have been assessed by the Group's internal reservoir engineers, utilising geological, geophysical, engineering and financial data
3 The Group's 2P reserves have been audited by a recognised Competent Person in accordance with the definitions set out under the 2018 Petroleum Resources Management System and supporting guidelines issued by the Society of Petroleum Engineers
4 Includes expansion of Seligi gas agreement in Malaysia
5 The above proven and probable reserves include volumes that will be consumed as fuel gas, including c.6.4 MMboe at Magnus, c.0.7 MMboe at Kraken, c.0.2 MMboe at Golden Eagle and c.0.1 MMboe at Scolty Crathes
6 The above 2P reserves at 31 December 2024 on an entitlement basis is 157 MMboe (North Sea 132 MMboe and South East Asia 25 MMboe)
7 Contingent resources are quoted on a working interest basis and relate to technically recoverable hydrocarbons for which commerciality has not yet been determined and are stated on a best technical case or 2C basis
8 2C contingent resources at 31 December 2024 include the volumes associated with the Group's PSC award at DEWA in Malaysia, as well as the relinquishment of the PM409 exploration licence
9 Rounding may apply

Risks and uncertainties

Management of risks and uncertainties

Consistent with the Group's purpose, the Board has articulated EnQuest's strategic vision to be the partner of choice for responsible management of existing energy assets, applying our core capabilities to create value through the transition.

EnQuest seeks to balance its risk position between investing in activities that can achieve its near-term targets, including those associated with reducing emissions, and those which can drive future growth with appropriate returns, including capitalising on any opportunities that may present themselves, and the continuing need to remain financially disciplined. This combination drives cost efficiency and cash flow generation, facilitating continued reduction in the Group's debt.

In pursuit of its strategy, EnQuest has to manage a variety of risks. Accordingly, the Board has established a Risk Management Framework ('RMF') to enhance effective risk management within the following Board-approved overarching statements of risk appetite:

- The Group makes investments and manages the asset portfolio against agreed key performance indicators consistent with the strategic objectives of enhancing net cash flow, reducing leverage, reducing emissions, managing costs, diversifying its asset base and pursuing new energy and decarbonisation opportunities;
- The Group seeks to embed a culture of risk management within the organisation corresponding to the risk appetite which is articulated for each of its principal risks;
- The Group seeks to avoid reputational risk by ensuring that its operational and HSEA processes, policies and practices reduce the potential for error and harm to the greatest extent practicable by means of a variety of controls to prevent or mitigate occurrence; and
- The Group sets clear tolerances for all material operational risks to minimise overall operational losses, with zero tolerance for criminal conduct.

The Board reviews the Group's risk appetite annually in light of changing market conditions and the Group's performance and strategic focus. Senior management periodically reviews and updates the Group Risk Register based on the individual risk registers of the business. The Board also periodically reviews (with senior management) the Group Risk Register, an assurance map and controls review, a Risk Report (focused on identifying and mitigating the most critical and emerging risks through a systematic analysis of the Group's business, its industry and the global risk environment), and a Continuous Improvement Plan ('CIP') to ensure that key issues are being adequately identified and actively managed. In addition, the Group's Audit Committee oversees the effectiveness of the RMF while the Sustainability and Risk Committee provides a forum for the Board to review selected individual risk areas in greater depth.

As part of its strategic, business planning and risk processes, the Group considers how a number of macroeconomic themes may influence its principal risks. These are factors which the Group should be cognisant of when developing its strategy. They include, for example, long-term supply and demand trends for oil and gas and renewable energy, the evolution of the fiscal regime, developments in technology, demographics, the financial, physical and transition risks associated with climate change and other ESG trends, and how markets and the regulatory environment may respond, and the decommissioning of infrastructure in the UK North Sea and other mature basins. These themes are relevant to the Group's assessments across a number of its principal risks. The Group will continue to monitor these themes and the relevant developing policy environment at an international and national level, adapting its strategy accordingly.

For example, the Group has made further progress in the development and execution of its energy transition and decarbonisation strategy through the sanction of major decarbonisation projects across its existing infrastructure, as well as a suite of scalable renewable energy and decarbonisation projects under the management of Veri Energy, a wholly owned subsidiary of the Group.

The Group is also conscious that, as an operator of mature producing assets with limited appetite for exploration, it has only slight exposure to investments that do not deliver near-term returns and is therefore in a position to adapt and calibrate its exposure to new investments according to developments in relevant markets. This flexibility also ensures the Group can mitigate against the potential impact of 'stranded assets' (being those assets that are no longer able to earn an economic return as a result of changes associated with the transition to a low-carbon economy).

Within the Group's RMF, the Sustainability and Risk Committee has categorised all risk areas faced by the Group into a 'Risk Library' of 19 overarching risks. For each risk area, 'Risk Bowties' are used to identify risk causes and impacts, with these mapped against preventative and containment controls used to manage the risks to acceptable levels (see diagram below). These Risk Bowties are periodically reviewed to ensure they remain fit for purpose.

The Board, cognisant of the changes to the UK Corporate Governance Code during 2024 (and Provision 29 for future financial years), supported by the Audit Committee and the Sustainability and Risk Committee, has reviewed the Group's system of risk management and internal control for the period from 1 January 2024 to the date of this report and carried out a robust assessment of the Group's emerging and principal risks and the procedures in place to identify and mitigate these risks. A Risk Management Framework Performance report is produced and reviewed at each Sustainability and Risk Committee meeting in support of this review. The Group will report on the updated UK Corporate Governance Code 2024 changes as appropriate.

Near-term and emerging risks

As outlined previously, the Group's RMF is embedded at all levels of the organisation with asset risk registers, regional and functional risk registers and ultimately an enterprise-level 'Risk Library'. This integration enables the Group to identify quickly, escalate and appropriately manage emerging risks, and how these ultimately impact on the enterprise-level risk and their associated 'Risk Bowties'. In turn, this ensures that the preventative and containment controls in place for a given risk are reviewed and remain robust based upon the identified risk profile. It also drives the required prioritisation of in-depth reviews to be undertaken by the Sustainability and Risk Committee, which are now integrated into the Group's internal audit programme for review. During the year, six Risk Bowties were reviewed, ensuring that all 19 of the Group's identified risks have been reviewed within the targeted three-year cycle.

ONGOING GEOPOLITICAL SITUATION

The Group has continued to assess its commercial and IT security arrangements and does not consider it has a material adverse exposure to the geopolitical situation with respect to the conflicts in Western Europe or the Middle East, although recognises that the situations have caused oil price volatility. The Group continues to monitor its position to ensure it remains compliant with any sanctions in place.

Climate change risks

While not considered an emerging risk, given the focus on climate-related risks for energy companies, EnQuest has provided further detail below on its assessment of this risk within the Group's Risk Library.

CLIMATE CHANGE

RISK

The Group recognises that climate change concerns and related regulatory developments could impact a number of the Group's principal risks, such as oil and gas price, financial, reputational and fiscal risk and government take, which are disclosed later in this report.

APPETITE

EnQuest recognises that the oil and gas industry, alongside other key stakeholders such as governments, regulators and consumers, must all play a part in reducing the impact of carbon-related emissions on climate change, and is committed to contributing positively towards the drive to net zero through the energy transition through reducing Scope 1 and Scope 2 emissions from existing operations. A decarbonisation strategy is being pursued through EnQuest's wholly owned subsidiary, Veri Energy, which was established to drive decarbonisation and renewable energy business opportunities.

The Group's risk appetite for climate change risk is reported against the Group's impacted principal risks.

MITIGATION

Mitigations against the Group's principal risks potentially impacted by climate change are reported later in this report.

The Group has an emissions management strategy and is committed to a 10% reduction in Scope 1 and 2 emissions over three years against a rolling year-end baseline. These targets are directly linked to organisation-wide remuneration via the Group Performance Share Plan. The first three-year period of emission reduction targets covered the 2023 out-turn versus a 2020 baseline, and in this period the Group achieved a reduction of 23% through improvements in operational performance, minimising flaring and venting where possible, and the application of appropriate and economic improvement initiatives.

For 2024, the rolling emission reduction strategy shifted to a new baseline of verified 2021 emissions and, when measured against this, the Group's year-end 2024 emissions achieved an 8.2% reduction against a year-end 2021 baseline, falling short of the 10% emission reduction target. Exceptional decarbonisation efforts in 2021 reduced baseline emissions by 16% compared to 2020, far surpassing the targeted 3% year-on-year reduction.

Looking ahead, EnQuest has initiated significant decarbonisation workstreams across its existing portfolio, including a Flare Gas Recovery Project at Magnus, the New Stabilisation Facility and long-term power solution at the Sullom Voe Terminal ('SVT'), and the potential for a Bressay gas line to power Kraken operations.

Following the establishment of Veri Energy during 2023, the Group's business model incorporates a focus on repurposing existing infrastructure to support its renewable energy and decarbonisation ambitions, centred around SVT.

EnQuest has reported on all of the greenhouse gas emission sources within its operational control required under the Companies Act 2006 (Strategic Report and Directors' Reports) Regulations 2013 and The Companies (Directors' Report) and Limited Liability Partnerships (Energy and Carbon Report) Regulations 2018.

The Group's focus on short-cycle investments drives an inherent mitigation against the potential impact of 'stranded assets'.

Key business risks

The Group's principal risks (identified from the 'Risk Library') are those which could prevent the business from executing its strategy and creating value for shareholders or lead to a significant loss of reputation. The Board has carried out a robust assessment of the principal and emerging risks facing the Group at its February meeting, including those that would threaten its business model, future performance, solvency or liquidity. Further to this assessment, the Board has committed to reviewing its principal risks and uncertainties during 2025 as part of its preparation for reporting against the 2024 changes to provision 29 of the Code.

Cognisant of the Group's purpose and strategy, the Board is satisfied that the Group's risk management system works effectively in assessing and managing the Group's risk appetite and has supported a robust assessment by the Directors of the principal risks facing the Group.

Set out on the following pages are:

The principal risks and mitigations;

- An estimate of the potential impact and likelihood of occurrence after the mitigation actions, along with how these have changed in the past year and which of the Group's KPIs could be impacted by this risk; and
- An articulation of the Group's risk appetite for each of these principal risks.

Among these, the key risks the Group currently faces are materially lower oil prices for an extended period (see 'Oil and gas prices' risk on page 22), and/or a materially lower than expected production performance for a prolonged period (see 'Production' risk on page 22 and 'Reserves estimation and replacement' on page 26), which could reduce the Group's cash generation, which may in turn impact the Company's ability to comply with the requirements of its debt facilities and/or execute growth opportunities.

HEALTH, SAFETY AND ENVIRONMENT ('HSE')

RISK

Oil and gas development, production and exploration activities are by their very nature complex, with HSE risks covering many areas, including major accident hazards, personal health and safety, compliance with regulatory requirements, asset integrity issues and potential environmental impacts, including those associated with climate change.

APPETITE

The Group's principal aim is SAFE Results with no harm to people and respect for the environment. Should operational results and safety ever come into conflict, employees have a responsibility to choose safety over operational results. Every employee is empowered to stop operations for safety-related reasons.

The Group's desire is to maintain upper quartile HSE performance measured against suitable industry metrics.

In 2024, EnQuest's Lost Time Incident frequency rate[1] ('LTIF') of 1.55 and two hydrocarbon releases challenged this objective. The lost time injuries were all associated with routine repetitive tasks. The root causes have been assessed and the Group is working closely with the contractors involved to ensure that everyone is aligned with EnQuest's safety culture, trained on equipment and procedures and empowered to stop a task should a safer method be identified. The hydrocarbon releases did not have common root causes and occurred at two different locations. All events were subject to thorough investigation and no systemic failure was identified within EnQuest systems.

All of the injurious events in 2024 were associated with external contractors, reflecting the high level of project and decommissioning activities that rely on these services. Regardless, the Group takes its responsibility seriously and has provided additional resources to support contractors to ensure that EnQuest's fundamental aim of ensuring no harm to people and respect for the environment is given the highest priority.

MITIGATION

The Group's HSE Policy is fully integrated across its operated sites and this enables a consistent focus on HSE. There is a strong assurance programme in place to ensure that the Group complies with its policy and principles and regulatory commitments.

The Group maintains, in conjunction with its core contractors, a comprehensive programme of assurance activities and has undertaken a series of in-depth reviews into the Risk Bowties that have demonstrated the robustness of the management process and identified opportunities for improvement which are implemented on a prioritised risk basis. The Group-aligned HSE Continuous Improvement Plan promotes a culture of accountability and performance in relation to HSE matters. The purpose of this plan is to ensure that everyone understands what is expected of them by having realistic standards, governance, and capabilities to add value and support the business. HSE performance is discussed at each Board meeting and the mitigation of HSE risk continues to be a core responsibility of the Sustainability and Risk Committee. During 2024, the Group continued to focus on the control of major accident hazards and SAFE Behaviours.

In addition, the Group has positive and transparent relationships with the UK Health and Safety Executive and Department for Energy Security and Net Zero, and the Malaysian regulator, PETRONAS Malaysia Petroleum Management.

Potential impact

Medium (2023: Medium)

LIKELIHOOD

Medium (2023: Medium)

CHANGE FROM LAST YEAR

EnQuest respects the hazards associated with oil and gas development and production in harsh environments and has applied continued focus to the safety and wellbeing of its people and assets. As a result, the potential impact and likelihood remains in line with 2023. Through our HSE processes, there is continuous focus on the management of the barriers that prevent hazards occurring. The Group has a strong, open and transparent reporting culture and monitors both leading and lagging indicators and incurs substantial costs in complying with HSE requirements. The Group's overall record on HSE has been good and is achieved by working closely and openly with contractors, verifiers and regulators to identify potential improvements through an active assurance process and implement plans to close any gaps in a timely manner.

RISK APPETITE

Low (2023: Low)

OIL AND GAS PRICES

RISK

A material decline in oil and gas prices adversely affects the Group’s operations and financial condition as the Group’s revenue depends substantially on oil prices.

APPETITE

The Group recognises that considerable exposure to this risk is inherent to its business but is committed to protecting cash flows in line with the terms of its reserve based lending (‘RBL’) facility.

MITIGATION

This risk is being mitigated by a number of measures.

As an operator of mature producing assets with limited appetite for exploration, the Group has limited exposure to investments which do not deliver near-term returns and is therefore in a position to adapt and calibrate its exposure to new investments according to developments in relevant markets.

The Group monitors oil price sensitivity relative to its capital commitments and its assessment of the funds required to support investment in the development of its resources. The Group will therefore regularly review and implement suitable programmes to hedge against the possible negative impact of changes in oil prices within the terms of its established policy (see page 64) and the terms of the Group’s RBL facility, which requires hedging of EnQuest’s entitlement sales volumes (see page 64). To mitigate oil price volatility, the Directors have hedged a total of 3.1 MMbbls from 1st April 2025 for the next 12 months with an average floor price of $69.6/bbl and a further 1.3 MMbbls in the subsequent 12 month period with an average floor price of $68.3/bbl, in each case predominantly utilising swaps. The Directors, in line with Group policy and the terms of its RBL facility, will continue to pursue hedging at the appropriate time and price.

The Group has an established in-house trading and marketing function to enable it to enhance its ability to mitigate the exposure to volatility in oil prices.

Further, the Group’s focus on production efficiency supports mitigation against a low oil price environment.

Potential impact

High (2023: High)

Likelihood

High (2023: High)

CHANGE FROM LAST YEAR

The potential impact and likelihood remain high, reflecting the uncertain economic outlook, including possible impacts from a global recession, geopolitical tensions and associated sanctions, and the potential acceleration of ‘peak oil’ demand.

The Group recognises that climate change concerns and related regulatory developments are likely to reduce demand for hydrocarbons over time. This may be mitigated by correlated constraints on the development of new supply. Further, oil and gas will remain an important part of the energy mix, especially in developing regions.

RISK APPETITE

Medium (2023: Medium)

PRODUCTION

RISK

The Group’s production is critical to its success and is subject to a variety of risks, including subsurface uncertainties, operating in a mature field environment, potential for significant unexpected shutdowns, and unplanned expenditure (particularly where remediation may be dependent on suitable weather conditions offshore).

Lower than expected reservoir performance or insufficient addition of new resources may have a material impact on the Group’s future growth.

Longer-term production is threatened if low oil prices or prolonged field shutdowns and/or underperformance requiring high-cost remediation bring forward decommissioning timelines.

APPETITE

Since production efficiency and meeting production targets are core to EnQuest’s business, the Group seeks to maintain a high degree of operational control over producing assets in its portfolio. EnQuest has a very low tolerance for operational risks to its production (or the support systems that underpin production).

MITIGATION

The Group's programme of asset integrity and assurance activities provide leading indicators of significant potential issues, which may result in unplanned shutdowns, or which may in other respects have the potential to undermine asset availability and uptime. The Group continually assesses the condition of its assets and operates extensive maintenance and inspection programmes designed to minimise the risk of unplanned shutdowns and expenditure.

The Group monitors both leading and lagging KPIs in relation to its maintenance activities and liaises closely with its downstream operators to minimise pipeline and terminal production impacts.

Production efficiency is continually monitored, with losses being identified and remedial and improvement opportunities undertaken as required. A continual, rigorous cost focus is also maintained.

Life of asset production profiles are audited by independent reserves auditors. The Group also undertakes regular internal reviews. The Group's forecasts of production are risked to reflect appropriate production uncertainties.

The Sullom Voe Terminal has a good safety record, and its safety and operational performance levels are regularly monitored and challenged by the Group and other terminal owners and users to ensure that operational integrity is maintained. Further, EnQuest is committed to transforming the Sullom Voe Terminal to ensure it remains competitive and well placed to maximise its useful economic life and support the future of the North Sea.

The Group actively continues to explore the potential of alternative transport options and developing hubs that may provide both risk mitigation and cost savings.

The Group also continues to consider new opportunities for expanding production and has recently added diversified growth to its production base through an expansion of the Seligi gas agreement and the Group's agreement to acquire the Block 12W production assets in Vietnam.

Potential impact

High (2023: High)

Likelihood

Medium (2023; Medium)

CHANGE FROM LAST YEAR

There has been no material change in the potential impact or likelihood. The Group revised its 2024 production guidance to slightly below its original guidance for the year and continues to focus on key maintenance activities during planned shutdowns and procuring a stock of critical spares to support facility uptime.

RISK APPETITE

Low (2023: Low)

FINANCIAL

RISK

Inability to fund financial commitments or maintain adequate cash flow and liquidity and/or reduce costs.

Significant reductions in the oil price, production and/or the funds available under the Group's RBL facility would likely have a material impact on the Group's ability to repay or refinance its existing credit facilities and invest in its asset base. Prolonged low oil prices, cost increases, including those related to an environmental incident, and production delays or outages, could threaten the Group's liquidity and/or ability to comply with relevant covenants. Further information is contained in the Financial review, particularly within the going concern and viability disclosures on page 16.

APPETITE

The Group remains focused on further reducing its leverage levels, targeting 0.5x EnQuest net debt to EBITDA ratio on a mid- cycle oil price basis, maintaining liquidity, controlling costs and complying with its obligations to finance providers while delivering shareholder value.

MITIGATION

Balance sheet management remains a strategic priority. During 2024, the Group's free cash flow generation and the repayment of a vendor loan provided to RockRose as part of the 2023 Bressay transaction drove a $95.1 million reduction in EnQuest net debt to $385.8 million at 31 December 2024, with the EnQuest net debt to adjusted EBITDA ratio maintained at 0.6x. During the year, EnQuest also further optimised its capital structure through the successful high yield bond tap and repayment in full of both the RBL and Term Loan facilities. Repayment of the term loan, which had second lien security, added additional access to the RBL while the year-end 2024 redetermination resulted in an increase to the available funds under the RBL. At 27 March 2025, the Group's RBL facility was undrawn following repayments totalling $140.0 million in the first quarter of 2024, ensuring the Group remains ahead of the amended facility amortisation schedule and within its borrowing base limits.

Ongoing compliance with the financial covenants under the Group's reserve based lending facility is actively monitored and reviewed. EnQuest generates operating cash inflow from the Group's producing assets and reviews its cash flow requirements on an ongoing basis to ensure it has adequate resources for its needs.

Where costs are incurred by external service providers, the Group actively challenges operating costs. The Group also maintains a framework of internal controls.

These steps, together with other mitigating actions available to management, are expected to provide the Group with sufficient liquidity to meet its obligations as they fall due.

Potential impact

High (2023: High)

Likelihood

Medium (2023: High)

CHANGE FROM LAST YEAR

There is no change to the potential impact but the likelihood has reduced. Against a backdrop of improved fiscal certainty and relatively stable oil price environment, the Group has significantly reduced its debt and successfully refinanced certain of its debt facilities in 2024. This maximises available financial capacity, with funds available under the Group's RBL further increased in January 2025 following the annual redetermination process (see the going concern disclosure on page 16).

However, factors such as climate change, other ESG concerns, oil price volatility and geopolitical risks continue to impact investors' and insurers' acceptable levels of oil and gas sector exposure. In addition, the cost of emissions trading allowances may trend upward along with the potential for insurers to be reluctant to provide surety bonds for decommissioning, thereby requiring the Group to fund decommissioning security through its balance sheet.

RISK APPETITE

Medium (2023: Medium)

COMPETITION

RISK

The Group operates in a competitive environment across many areas, including the acquisition of oil and gas assets, the marketing of oil and gas, the procurement of oil and gas services, including drilling rigs for development and decommissioning projects, and access to experienced and capable personnel.

APPETITE

The Group operates in a mature industry with well-established competitors and aims to be the leading operator in the sector.

MITIGATION

The Group has strong technical, commercial and business development capabilities to ensure that it is well positioned to identify and execute potential acquisition opportunities, utilising innovative structures, which may include the Group's competitive advantage of approximately $2.1 billion of UK tax losses, as may be appropriate.

The Group maintains good relations with oil and gas service providers and constantly keeps the market under review. EnQuest has a dedicated marketing and trading group of experienced professionals responsible for maintaining relationships across relevant energy markets, thereby ensuring the Group achieves the highest possible value for its production. Human Resources risk is covered specifically on page 30.

Potential impact

High (2023: High)

Likelihood

High (2023: High)

CHANGE FROM LAST YEAR

The potential impact and likelihood remain unchanged, with the confirmed changes of the UK EPL and removal of investment allowances likely to impact industry participants' investment views of the UK North Sea, a number of competitors assessing the acquisition of available oil and gas assets and the rising potential for consolidation. Operating in a competitive industry may result in higher than anticipated prices for the acquisition of assets and licences.

RISK APPETITE

Medium (2023: Medium)

IT SECURITY AND RESILIENCE

RISK

The Group is exposed to risks arising from interruption to, or failure of, IT infrastructure. The risks of disruption to normal operations range from loss in functionality of generic systems (such as email and internet access) to the compromising of more sophisticated systems that support the Group's operational activities. These risks could result from malicious interventions such as cyber-attacks or phishing exercises.

APPETITE

The Group endeavours to provide a secure IT environment that is able to resist and withstand any attacks or unintentional disruption that may compromise sensitive data, impact operations, or destabilise financial systems; it has a very low appetite for this risk.

MITIGATION

The Group has established IT capabilities and endeavours to be in a position to defend its systems against disruption or attack.

A number of tools to strengthen employee awareness continue to be utilised, including videos, presentations, Viva Engage posts and poster campaigns.

The Audit Committee has reviewed the Group's cyber-security measures and its IT resourcing model, noting the Group has a dedicated cyber-security manager. Work on assessing the cyber-security environment (including internal audit reviews) and implementing improvements as necessary has continued during 2024. A number of actions were undertaken to further strengthen our controls including the following:

- Implementation of IT Governance, Risk and Compliance framework to address UK Corporate Governance Code 2024
- Security strengthened through actions to improve privileged access and password changes to finance system
- Insider threat penetration testing carried out, alongside a ransomware threat and attack desktop exercise facilitated by a third party cyber security company
- Air gapped (segregated) back-ups, meaning they are separately available with minimal operational impact should the main data be hit by ransomware. An added feature of this initiative is continuous scanning of all EnQuest's back-ups for the presence of ransomware
- Established a Security Operations Centre for 24/7 live monitoring of Group's cyber environment, improving cyber threat detection and intervention capability
- Upgraded the Group's existing brand protection service to include 'Identity Protection' module. This is utilised to identify EnQuest IT users' leaked credentials
- Initiated a review of the Group's supply chain/vendor cyber security risk management environment, with 31 vendors assessed to date
- Established a Group-wide vulnerability management process, enabling the continuous review and identification of high risk vulnerabilities and planned remediation

Potential impact

Medium (2023: Medium)

Likelihood

High (2023: High)

CHANGE FROM LAST YEAR

There is no change to the impact or likelihood of this risk.

RISK APPETITE

Low (2023: Low)

PORTFOLIO CONCENTRATION

RISK

The Group's existing assets are primarily concentrated in the UK North Sea around a limited number of infrastructure hubs and existing production (principally oil) is from mature fields. This amplifies exposure to key infrastructure (including ageing pipelines and terminals), political/fiscal changes and oil price movements.

APPETITE

The Group is pursuing an international growth and diversification strategy that includes an increased gas component with the extent of portfolio concentration moderated by existing production generated in Malaysia and further business development activities in South East Asia, including the expansion of the Seligi Gas Agreement in Malaysia and agreement to acquire hydrocarbon assets in Vietnam.

MITIGATION

This risk is mitigated in part through acquisitions. For all acquisitions, the Group uses a number of business development resources, both in the UK and internationally, to liaise with vendors/governments and evaluate and transact. This includes performing extensive due diligence (using in-house and external personnel) and actively involving executive management and the Board in reviewing commercial, technical and other business risks together with mitigation measures.

The Group also constantly keeps its portfolio under rigorous review and, accordingly, actively considers the potential for making disposals, executing development projects, expanding hubs and investing in gas assets, export capability or renewable energy and decarbonisation projects where such opportunities are consistent with the Group's focus on enhancing net revenues, generating cash flow and strengthening the balance sheet.

The Group has made good progress with its decarbonisation strategy, identifying the three key focus areas of carbon storage, electrification/renewable power and production of e-fuels through its subsidiary company, Veri Energy, which could provide diversified revenue opportunities in the long term.

Potential impact

High (2023: High)

Likelihood

High (2023: High)

CHANGE FROM LAST YEAR

There has been no material change in the potential impact or likelihood although the Group is expected to increase its exposure to gas, other geographies and other sources of income over time.

RISK APPETITE

Medium (2023: Medium)

RESERVES ESTIMATION AND REPLACEMENT

RISK

Failure to develop contingent and prospective resources or secure new licences and/or asset acquisitions and realise their expected value.

APPETITE

Reserves replacement is an element of the sustainability of the Group and its ability to grow. The Group has some tolerance for the assumption of risk in relation to the key activities required to deliver reserves growth, such as drilling and acquisitions.

MITIGATION

The Group puts a strong emphasis on subsurface analysis and employs industry-leading professionals. The Group continues to recruit in a variety of technical positions which enables it to manage existing assets and evaluate the acquisition of new assets and licences.

All analysis is subject to internal peer-review process and, where appropriate, external review and relevant stage gate processes. All reserves are currently externally reviewed by a Competent Person.

The Group has material reserves and resources at Magnus, Kraken and PM8/Seligi. Some of the resources volumes can be accessed through low-cost workovers, drilling and tie-backs to existing infrastructure.

The Group continues actively to consider potential opportunities to acquire new production resources and development projects that meet its investment criteria. In 2024, the Group successfully secured the Seligi Phase 1b project (13.7 MMboe net WI reserves) with anticipated first gas in 2026. Additionally, the Group was awarded a Production Sharing Contract for a new discovered resource opportunity block (DEWA) in Malaysia, which has the potential to be developed in the next few years with estimated resources of 17.7 MMboe net WI.

The Group's acquisition in Vietnam is expected to complete in the second quarter of 2025, adding 7.5 MMboe of net 2P reserves.

Potential impact

High (2023: High)

Likelihood

Medium (2023: Medium)

CHANGE FROM LAST YEAR

There is no change to the potential impact or likelihood of this risk. There have been two new secured projects in Malaysia, Seligi Phase 1b and the DEWA block. It is also expected that the Group will complete the acquisition of Harbour Energy's asset in Vietnam in 2025 which will further improve the Reserves Replacement Ratio.

Other aspects still remain, such as possible low oil prices and higher development cost and declining asset performance which accelerate cessation of production and can potentially affect development of contingent and prospective resources and/or reserves certifications.

Given EnQuest's limited appetite for exploration, the Labour Government's manifesto promise not to issue new oil and gas exploration licences in the UK is not expected to have a material impact on the Group.

RISK APPETITE

Medium (2023: Medium)

PROJECT EXECUTION AND DELIVERY

RISK

The Group's success will be partially dependent upon the successful execution and delivery of potential future projects that are undertaken, including infill development, tie-back and facility modifications, decommissioning, decarbonisation and new energy opportunities in the UK.

APPETITE

The efficient delivery of projects has been a key feature of the Group's long-term strategy. The Group's appetite is to identify and implement short-cycle development projects such as infill drilling, near-field tie-backs and facility modifications to enable emission reduction initiatives in its Upstream business, industrialise decommissioning projects to ensure cost efficiency and unlock new energy and decarbonisation opportunities through innovative commercial structures and redevelopment of SVT. While the Group necessarily assumes significant risk when it sanctions a new project (for example, by incurring costs against oil price or cost of emission allowances assumptions), or a decommissioning programme, it requires that risks to efficient project delivery are minimised.

MITIGATION

The Group has teams which are responsible for the planning and execution of new projects with a dedicated team for each project. The Group has detailed controls, systems and monitoring processes in place, notably the Capital Projects Delivery Process and the Decommissioning Projects Delivery Process, to ensure that deadlines are met, costs are controlled and that design concepts and Field Development/Decommissioning Plans are adhered to and implemented. These are modified when circumstances require and only through a controlled management of change process and with the necessary internal and external authorisation and communication. The Group's UK decommissioning programmes are managed by a dedicated directorate with an experienced team who are driven to deliver projects safely at the lowest possible cost and associated emissions.

Within Veri Energy, the Group is working with experienced third-party organisations and aims to utilise innovative commercial structures to develop new energy and decarbonisation opportunities.

The Group also engages third-party assurance experts to review, challenge and, where appropriate, make recommendations to improve the processes for project management, cost control and governance of major projects. EnQuest ensures that responsibility for delivering time-critical supplier obligations and lead times are fully understood, acknowledged and proactively managed by the most senior levels within supplier organisations.

Potential impact

Medium (2023: Medium)

Likelihood

Medium (2023: Low)

CHANGE FROM LAST YEAR

The potential impact remains unchanged. As the Group focuses on reducing its debt, its current appetite is to pursue short-cycle development projects and to manage its decommissioning and Infrastructure and New Energy projects over an extended period of time. However, the volume of projects across the portfolio in the execution phase, including the material right-sizing projects ongoing at SVT, increase the likelihood of this risk impacting Group operations.

RISK APPETITE

Medium (2023: Medium)

FISCAL RISK AND GOVERNMENT TAKE

RISK

Unanticipated changes in the regulatory or fiscal environment can affect the Group's ability to deliver its strategy/business plan and potentially impact revenue and future developments.

APPETITE

Given the Group's strategy to grow in the UK and internationally, including in its nascent new energy business, it must be tolerant of certain inherent exposure.

MITIGATION

It is difficult for the Group to predict the timing or severity of such changes. However, through Offshore Energies UK and other industry associations, the Group engages with government and other appropriate organisations in order to keep abreast of expected and potential changes. The Group also takes an active role in making appropriate representations as it has done throughout the implementation period of the EPL.

All business development or investment activities recognise potential tax implications and the Group maintains relevant internal tax expertise.

At an operational level, the Group has procedures to identify impending changes in relevant regulations to ensure legislative compliance.

Potential impact

High (2023: High)

Likelihood

Medium (2023: Medium)

CHANGE FROM LAST YEAR

There has been no material change in the potential impact or likelihood given the enactment of the Labour Government's expected changes to the EPL.

RISK APPETITE

Medium (2023: Medium)

INTERNATIONAL BUSINESS

RISK

While the majority of the Group's activities and assets are in the UK, the international business is still material and, with recent acquisitions, is growing. The Group's international business is subject to the same risks as the UK business (for example, HSEA, production and project execution). However, there are additional risks that the Group faces, including security of staff and assets, political, foreign exchange and currency control, taxation, legal and regulatory, cultural and language barriers and corruption.

APPETITE

In light of its long-term growth strategy, the Group seeks to expand and diversify its production (geographically and in terms of quantum and product mix); as such, it is tolerant of assuming certain commercial risks which may accompany the opportunities it pursues.

However, such tolerance does not impair the Group's commitment to comply with legislative and regulatory requirements in the jurisdictions in which it operates. Opportunities should enhance net revenues and facilitate strengthening of the balance sheet.

MITIGATION

Prior to entering a new country, EnQuest evaluates the host country to assess whether there is an adequate and established legal and political framework in place to protect and safeguard first its expatriate and local staff and, second, any investment within the country in question.

When evaluating international business risks, executive management conducts a review of commercial, technical, ethical and other business risks, together with mitigation and considers how risks can be managed by the business on an ongoing basis.

EnQuest looks to employ suitably qualified host country staff and work with good quality local advisers to ensure it complies with national legislation, business practices and cultural norms, while at all times ensuring that staff, contractors and advisers comply with EnQuest's business principles, including those on financial control, cost management, fraud and corruption.

Where appropriate, the risks may be mitigated by entering into a joint venture with partners with local knowledge and experience.

After country entry, EnQuest maintains a dialogue with local and regional government, particularly with those responsible for oil, energy and fiscal matters, and may obtain support from appropriate risk consultancies. When there is a significant change in the risk to people or assets within a country, the Group takes appropriate action to safeguard people and assets.

Potential impact

Medium (2023: Medium)

Likelihood

Medium (2023: Medium)

CHANGE FROM LAST YEAR

There has been no material change in the impact or likelihood. The Group's new country entry into Vietnam is fully staffed, thus ensuring a continuation of experienced, capable asset support.

RISK APPETITE

Medium (2023: Medium)

JOINT VENTURE PARTNERS

RISK

Failure by joint venture parties to fund their obligations.

Dependence on other parties where the Group is non-operator.

APPETITE

The Group requires partners of high integrity. It recognises that it must accept a degree of exposure to the creditworthiness of partners and evaluates this aspect carefully as part of every investment decision.

MITIGATION

The Group operates regular cash call and billing arrangements with its co-venturers to mitigate the Group's credit exposure at any one point in time and keeps in regular dialogue with each of these parties to ensure payment. Risk of default is mitigated by joint operating agreements allowing the Group to take over any defaulting party's share in an operated asset and rigorous and continual assessment of the financial situation of partners.

The Group generally prefers to be the operator and maintains regular dialogue with its partners to ensure alignment of interests and to maximise the value of joint venture assets, taking account of the impact of any wider developments.

Potential impact

Medium (2023: Medium)

Likelihood

Medium (2023: Low)

CHANGE FROM LAST YEAR

There has been no material change in the potential impact but the challenging UK fiscal environment increases the likelihood of default for EnQuest's joint venture partners.

RISK APPETITE

Medium (2023: Medium)

REPUTATION

RISK

The reputational and commercial exposures to a major offshore incident, including those related to an environmental incident, or non-compliance with applicable law and regulation and/or related climate change disclosures, are significant. Similarly, it is increasingly important that EnQuest clearly articulates its approach to and benchmarks its performance against relevant and material ESG factors.

APPETITE

The Group has no tolerance for conduct which may compromise its reputation for integrity and competence.

MITIGATION

All activities are conducted in accordance with approved policies, standards and procedures. Interface agreements are agreed with all core contractors, ensuring that they comply with equivalent standards.

The Group requires adherence to its Code of Conduct and runs ethics and compliance programmes to provide assurance on conformity with relevant legal and ethical requirements. In 2024, the Group launched a Handrails website – a standalone website with various ethics and compliance policies, complemented by external training within the website.

The Group undertakes regular audit activities to provide assurance on compliance with established policies, standards and procedures.

All EnQuest personnel and contractors are required to undertake an annual anti-bribery and corruption course, an anti-facilitation of tax evasion course and a data privacy course.

All personnel are authorised to shut down operations for safety-related reasons.

The Group has a clear ESG strategy, with a focus on health and safety (including asset integrity), emission reductions, looking after its employees, positively impacting the communities in which the Group operates, upholding a robust Risk Management Framework and acting with high standards of integrity. The Group is successfully implementing this strategy.

Potential impact

High (2023: High)

Likelihood

Low (2023: Low)

CHANGE FROM LAST YEAR

There has been no material change in the potential impact or likelihood.

RISK APPETITE

Low (2023: Low)

HUMAN RESOURCES

RISK

The Group's success continues to be dependent upon its ability to attract and retain key personnel and develop organisational capability to deliver strategic growth. Industrial action across the sector, or the availability of competent people, could also impact the operations of the Group.

APPETITE

As a lean organisation, the Group relies on motivated and high-quality employees to achieve its targets and manage its risks.

The Group recognises that the benefits of a flexible and diverse organisation require creativity and agility to protect against the risk of skills shortages.

MITIGATION

The Group has established an able and competent employee base to execute its principal activities. In addition, the Group seeks to maintain good relationships with its employees and contractor companies and regularly monitors the employment market to provide remuneration packages, bonus plans and long-term share-based incentive plans that incentivise performance and long-term commitment from employees to the Group.

The Group recognises that its people are critical to its success and is therefore continually evolving EnQuest's end-to-end people management processes, including recruitment and selection, career development and performance management. This ensures that EnQuest has the right person for each job and that appropriate training, support and development opportunities are provided, with feedback collated to drive continuous improvement while delivering SAFE Results.

The culture of the Group is an area of ongoing focus and employee feedback is frequently sought to understand employees' views on areas, including diversity and inclusion and wellbeing in order to develop appropriate action plans. Although it was anticipated that fewer young people may join the industry due to climate change-related factors, 2024 saw a further rise in the number of young professionals joining EnQuest, and we saw a 33% increase in employees under the age of 24. EnQuest aims to attract and sustain the best talent, recognising the value and importance of diversity. The emphasis around improved diversity in the Group's management and leadership is a main focal point for the Board. The Group recognises that there is a gender pay gap within the organisation but that there is no issue with equal pay for the same tasks.

The Group has reviewed the appropriate balance for its onshore teams between site, office, and home working to promote strong productivity and business performance facilitated by an engaged workforce, adopting a hybrid approach. EnQuest has now moved to a 4:1 office to work from home ratio in the UK to enhance productivity and motivate staff. The Group will continue to monitor such practices, adapting as necessary. The Group also maintains market-competitive contracts with key suppliers to support the execution of work where the necessary skills do not exist within the Group's employee base.

Executive and senior management retention, succession planning and development remain important priorities for the Board. It is a Board-level priority that executive and senior management possess the appropriate mix of skills and experience to realise the Group's strategy.

Potential impact

Medium (2023: Medium)

Likelihood

Medium (2023: Medium)

CHANGE FROM LAST YEAR

There has been no material change in the potential impact or likelihood.

RISK APPETITE

Medium (2023: Medium)

PRODUCTION DETAILS

Average daily production on a net working interest basis	**1 Jan 2024 to 31 Dec 2024**	**1 Jan 2023 to 31 Dec 2023**
	(Boepd)	**(Boepd)**
UK Upstream		
- Magnus	14,173	15,933
- Kraken	12,759	13,580
- Golden Eagle	3,328	4,199
- Other Upstream[1]	2,327	2,663
Total UK	**32,587**	**36,375**
Total Malaysia	**8,149**	**7,437**
Total EnQuest	**40,736**	**43,812**

[1] Other Upstream: Scolty/Crathes, Greater Kittiwake Area and Alba

KEY PERFORMANCE INDICATORS

	2024	2023	2022
ESG metrics:			
Group LTIF[1]	**1.55**	0.52	0.57
Scope 1 and Scope 2 Emissions (kilo-tonnes of CO_2 equivalent)	**1,068.4**	1,041.9	1,051.9
Business performance data:			
Production (Boepd)	**40,736**	43,812	47,259
Unit opex (production and transportation costs) ($/Boe)[2]	**25.3**	21.9	22.7
Cash expenditures ($ million)	**313.4**	211.1	174.8
Capital[2]	**252.9**	152.2	115.8
Decommissioning	**60.5**	58.9	59.0
Reported data:			
Cash generated from operations ($ million)	**685.9**	854.7	1,026.1
EnQuest net debt ($ million)[2]	**385.8**	480.9	717.1
Net 2P reserves (MMboe)	**169**	175	190

[1] Lost time incident frequency represents the number of incidents per million exposure hours worked (based on 12 hours for offshore and eight hours for onshore)
[2] See reconciliation of alternative performance measures within the 'Glossary – Non-GAAP Measures' starting on page 70

Group Income Statement

For the year ended 31 December 2024

	Notes	**2024** **$'000**	2023 $'000
Revenue and other operating income	4(a)	**1,180,709**	1,487,419
Cost of sales	4(b)	**(787,383)**	(946,752)
Gross profit/(loss)		**393,326**	540,667
Net impairment charge to oil and gas assets	9	**(71,414)**	(117,396)
General and administration expenses	4(c)	**(5,702)**	(6,348)
Other (expenses)/income	4(d)	**(4,682)**	(19,550)
Profit/(loss) from operations before tax and finance income/(costs)		**311,528**	397,373
Finance costs	5	**(159,422)**	(172,087)
Finance income	5	**14,508**	6,493
Profit/(loss) before tax		**166,614**	231,779
Income tax	6	**(72,841)**	(262,612)
Profit/(loss) for the year attributable to owners of the parent		**93,773**	(30,833)
Total comprehensive profit/(loss) for the year, attributable to owners of the parent		**93,773**	(30,833)

There is no comprehensive income attributable to the shareholders of the Group other than the profit/(loss) for the period. Revenue and operating profit/(loss) are all derived from continuing operations.

		$	$
Earnings per share	7		
Basic		**0.050**	(0.016)
Diluted		**0.049**	(0.016)

The attached notes 1 to 30 form part of these Group financial statements.

Group Balance Sheet
At 31 December 2024

	Notes	2024 $'000	2023 $'000
ASSETS			
Non-current assets			
Property, plant and equipment	9	**2,297,954**	2,296,740
Goodwill	10	**134,400**	134,400
Intangible assets	11	**20,563**	18,323
Deferred tax assets	6(c)	**506,481**	540,122
Trade and other receivables	15	**2,102**	–
Other financial assets	18	**38,459**	36,282
		2,999,959	3,025,867
Current assets			
Intangible assets	11	**1,138**	876
Inventories	12	**48,976**	84,797
Trade and other receivables	15	**230,971**	225,486
Current tax receivable		**1,256**	1,858
Cash and cash equivalents	13	**280,239**	313,572
Other financial assets	18	**69**	113,326
		562,649	739,915
TOTAL ASSETS		**3,562,608**	3,765,782
EQUITY AND LIABILITIES			
Equity			
Share capital and premium	19	**392,054**	393,831
Treasury shares	19	**(4,425)**	–
Share-based payments reserve		**13,949**	13,195
Capital redemption reserve	19	**2,006**	–
Retained earnings	19	**138,882**	49,702
TOTAL EQUITY		**542,466**	456,728
Non-current liabilities			
Loans and borrowings	17	**621,440**	747,812
Lease liabilities	23	**288,262**	288,892
Contingent consideration	21	**452,891**	461,271
Provisions	22	**710,976**	715,436
Deferred income	24	**138,095**	138,416
Trade and other payables	16	**–**	32,917
Deferred tax liabilities	6(c)	**104,698**	77,643
		2,316,362	2,462,387
Current liabilities			
Loans and borrowings	17	**43,417**	27,364
Lease liabilities	23	**46,994**	133,282
Contingent consideration	21	**20,403**	46,525
Provisions	22	**55,130**	79,861
Trade and other payables	16	**414,390**	347,409
Other financial liabilities	18	**21,580**	26,679
Current tax payable		**101,866**	185,547
		703,780	846,667
TOTAL LIABILITIES		**3,020,142**	3,309,054
TOTAL EQUITY AND LIABILITIES		**3,562,608**	3,765,782

The attached notes 1 to 30 form part of these Group financial statements.

The financial statements were approved by the Board of Directors and authorised for issue on 26 March 2025 and signed on its behalf by:

Jonathan Copus
Chief Financial Officer

Group Statement of Changes in Equity

For the year ended 31 December 2024

	Notes	Share capital $'000	Share premium $'000	Treasury shares $'000	Share-based payments reserve $'000	Capital redemption reserve $'000	Retained earnings $'000	Total $'000
Balance at 1 January 2023		**131,650**	**260,546**	–	**11,510**	–	**80,535**	**484,241**
Loss for the year		–	–	–	–	–	(30,833)	(30,833)
Total comprehensive expense for the year		–	–	–	–	–	(30,833)	(30,833)
Issue of shares to Employee Benefit Trust		1,635	–	–	(1,635)	–	–	–
Share-based payment		–	–	–	3,320	–	–	3,320
Balance at 31 December 2023		**133,285**	**260,546**	–	**13,195**	–	**49,702**	**456,728**
Profit for the year		**–**	**–**	**–**	**–**	**–**	**93,773**	**93,773**
Total comprehensive income for the year		**–**	**–**	**–**	**–**	**–**	**93,773**	**93,773**
Issue of shares to Employee Benefit Trust	19	**229**	**–**	**–**	**(229)**	**–**	**–**	**–**
Repurchase and cancellation of shares	19	**(2,006)**	**–**	**(4,425)**	**–**	**2,006**	**(4,593)**	**(9,018)**
Share-based payment	20	**–**	**–**	**–**	**983**	**–**	**–**	**983**
Balance at 31 December 2024		**131,508**	**260,546**	**(4,425)**	**13,949**	**2,006**	**138,882**	**542,466**

The attached notes 1 to 30 form part of these Group financial statements.

Group Statement of Cash Flows

For the year ended 31 December 2024

	Notes	**2024 $'000**	2023 $'000
CASH FLOW FROM OPERATING ACTIVITIES			
Cash generated from operations	29	**685,946**	854,746
Cash received from insurance		**–**	5,190
Cash (paid)/received on purchase of financial instruments		**(10,306)**	(5,795)
Cash paid in relation to amounts previously provided for		**(9,063)**	–
Decommissioning spend		**(60,544)**	(58,911)
Income taxes paid		**(97,264)**	(40,986)
Net cash flows from/(used in) operating activities		**508,769**	754,244
INVESTING ACTIVITIES			
Purchase of property, plant and equipment		**(249,165)**	(141,741)
Proceeds from farm-down	11,24	**1,263**	141,360
Vendor financing facility repaid/(loaned)	18(f),24	**107,518**	(141,360)
Purchase of intangible oil and gas assets	11	**(3,686)**	(10,467)
Purchase of other intangible assets	11	**(1,138)**	(876)
Payment of Magnus contingent consideration – Profit share	21	**(48,465)**	(65,506)
Payment of Golden Eagle contingent consideration – Acquisition	21	**–**	(50,000)
Interest received		**10,100**	5,895
Net cash flows (used in)/from investing activities		**(183,573)**	(262,695)
FINANCING ACTIVITIES			
Proceeds from loans and borrowings		**31,662**	190,657
Repayment of loans and borrowings		**(162,304)**	(427,736)
Payment for repurchase of shares		**(9,018)**	–
Payment of obligations under financing leases	23	**(130,065)**	(135,675)
Interest paid		**(83,162)**	(105,877)
Net cash flows (used in)/from financing activities		**(352,887)**	(478,631)
NET (DECREASE)/INCREASE IN CASH AND CASH EQUIVALENTS		**(27,691)**	12,918
Net foreign exchange on cash and cash equivalents		**(5,642)**	(957)
Cash and cash equivalents at 1 January		**313,572**	301,611
CASH AND CASH EQUIVALENTS AT 31 DECEMBER		**280,239**	313,572
Reconciliation of cash and cash equivalents			
Total cash at bank and in hand	13	**226,317**	313,028
Restricted cash	13	**53,922**	544
Cash and cash equivalents per balance sheet		**280,239**	313,572

The attached notes 1 to 30 form part of these Group financial statements.

Notes to the Group Financial Statements

For the year ended 31 December 2024

1. Corporate information

EnQuest PLC ('EnQuest' or the 'Company') is a public company limited by shares incorporated in the United Kingdom under the Companies Act and is registered in England and Wales and listed on the London Stock Exchange. The address of the Company's registered office is shown on the inside back cover of the Group Annual Report and Accounts.

EnQuest PLC is the ultimate controlling party. The principal activities of the Company and its subsidiaries (together the 'Group') are to responsibly optimise production, leverage existing infrastructure, deliver a strong decommissioning performance and explore new energy and decarbonisation opportunities.

The Group's financial statements for the year ended 31 December 2024 were authorised for issue in accordance with a resolution of the Board of Directors on 26 March 2025.

A listing of the Group's companies is contained in note 28 to these Group financial statements.

2. Basis of preparation

The financial information for the years ended 31 December 2024 and 2023 contained in this document does not constitute statutory accounts of Enquest plc (the Company), as defined in section 435 of the Companies Act 2006. The financial information for the years ended 31 December 2024 and 2023 has been extracted from the consolidated financial statements of Enquest plc and all its subsidiaries (the Group), which were authorised by the Board of Directors on 26 March 2025 and which will be delivered to the Registrar of Companies in due course. The auditor's report on those financial statements was unqualified and did not contain a statement under section 498 of the Companies Act 2006.

The consolidated financial statements have been prepared in accordance with United Kingdom international accounting standards ('IFRS') in conformity with the requirements of the Companies Act 2006. The accounting policies which follow set out those policies which apply in preparing the financial statements for the year ended 31 December 2024.

For the year ended 31 December 2024, the Group removed the separate disclosure of remeasurements and exceptional items from the presentation of the Group income statement to simplify their presentation for users of accounts and bring them more in line with peers. The Group continues to present various Alternative Performance Measures ('APMs') when assessing and discussing the Group's financial performance, balance sheet and cash flows that are not defined or specified under IFRS but consistent with the measurement basis applied to the financial statements. The Group uses these APMs, which are not considered to be a substitute for, or superior to, IFRS measures, to provide stakeholders with additional useful information to aid the understanding of the Group's underlying financial performance, balance sheet and cash flows by adjusting for certain items, such as those previously classified as remeasurements and exceptional items, which impact upon IFRS measures or, by defining new measures. See the Glossary – Non-GAAP Measures on page 70 for more information.

The Group financial information has been prepared on a historical cost basis, except for the fair value remeasurement of certain financial instruments, including derivatives and contingent consideration, as set out in the accounting policies. The presentation currency of the Group financial information is US Dollars ('$') and all values in the Group financial information are rounded to the nearest thousand ($'000) except where otherwise stated.

Going concern

The financial statements have been prepared on the going concern basis.

In recent years, EnQuest has focused on deleveraging and optimising its capital structure, to simplify its balance sheet and maximise available financial transactional capacity.

In 2024, the Group deleveraged further, reducing EnQuest net debt by $95.1 million, to $385.8 million at 31 December 2024. This was driven by robust adjusted free cash flow generation and repayment of the first of two vendor loans that was provided to RockRose as part of the 2023 Bressay farm-down. In the period EnQuest fully repaid its Reserve Based Lending ('RBL') facility (from $140.0 million) and completed a $160.0 million tap of its high yield bonds. By using this tap to repay a $150.0 million term loan facility, additional RBL capacity was opened. At 31 December 2024, EnQuest's net debt to adjusted EBITDA ratio was 0.6x. The Group ended 2024 with a positive RBL redetermination, which expanded RBL capacity by 34%. Cash and available facilities at 28 February 2025 totalled $549.0 million.

Against this robust backdrop, EnQuest continues to closely monitor and manage its funding position and liquidity requirements throughout the year, including monitoring forecast covenant results. Cash forecasts are regularly produced and sensitivities considered for, but not limited to, changes in crude oil prices (adjusted for hedging undertaken by the Group), production rates and costs. These forecasts and sensitivity analyses allow management to mitigate liquidity or covenant compliance risks in a timely manner.

The Group's latest approved business plan underpins management's base case ('Base Case'). It is in line with EnQuest's production guidance (including the acquisition and contribution of the Block 12W in Vietnam - completion expected in the second quarter of 2025) and an oil price assumption of $75.0/bbl is used for 2025 and 2026.

A reverse stress test has been performed on the Base Case. This indicates that an oil price of c.$40.0/bbl is required to maintain covenant compliance over the going concern period. The low level of this required price reflects the Group's strong liquidity position.

The Base Case has also been subjected to further testing through a scenario that explores the impact of the following plausible downside risks (the 'Downside Case'):

- 10% discount to Base Case prices resulting in Downside Case prices of $67.50/bbl for 2025 and 2026;
- Production risking of 5.0%; and
- 2.5% increase in operating costs.

The Base Case and Downside indicate that the Group is able to operate as a going concern and remain covenant compliant for 12 months from the date of publication of its full-year results.

After making appropriate enquiries and assessing the progress against the forecast, the Directors have a reasonable expectation that the Group will continue in operation and meet its commitments as they fall due over the going concern period. Accordingly, the Directors continue to adopt the going concern basis in preparing these financial statements.

New standards and interpretations
The following new standards became applicable for the current reporting period. No material impact was recognised upon application:
- Supplier Finance Arrangements (Amendments to IAS 7 and IFRS 7)
- Classification of Liabilities as Current or Non-current and Non-current Liabilities with Covenants (Amendments to IAS1)
- Lease Liability in a Sale and Leaseback (Amendment to IFRS 16)

Standards issued but not yet effective
At the date of authorisation of these financial statements, the Group has not applied the following new and revised IFRS Standards that have been issued but are not yet effective:

IFRS 9 and IFRS 7	*Amendments to the Classification and Measurement of Financial Instruments*
IFRS 18	*Presentation of financial statements*
IFRS 19	*Subsidiaries without Public Accountability: Disclosures*
Amendments to IAS 21	*Lack of Exchangeability*

The Directors do not expect that the adoption of the Standards listed above will have a material impact on the financial statements of the Group in future periods. The Directors noted IFRS 18 may change the presentation and disclosure information in the financial statements when effective.

Basis of consolidation
The consolidated financial statements incorporate the financial statements of EnQuest PLC and entities controlled by the Company (its subsidiaries) made up to 31 December each year. Control is achieved when 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, the results of subsidiaries acquired or disposed of during the year are included in profit or loss from the date the Company gains control until the date the Company ceases to control the subsidiary.

Where necessary, adjustments are made to the financial statements of subsidiaries to bring the accounting policies used into line with the Group's accounting policies. All intra-Group assets and liabilities, equity, income, expenses and cash flows relating to transactions between the members of the Group are eliminated on consolidation.

Joint arrangements
Oil and gas operations are usually conducted by the Group as co-licensees in unincorporated joint operations with other companies. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the consent of the relevant parties sharing control. The joint operating agreement is the underlying contractual framework to the joint arrangement, which is historically referred to as the joint venture. The Annual Report and Accounts therefore refers to 'joint ventures' as a standard term used in the oil and gas industry, which is used interchangeably with joint operations.

Most of the Group's activities are conducted through joint operations, whereby the parties that have joint control of the arrangement have the rights to the assets, and obligations for the liabilities relating to the arrangement. The Group recognises its share of assets, liabilities, income and expenses of the joint operation in the consolidated financial statements on a line-by-line basis. During 2024, the Group did not have any material interests in joint ventures or in associates as defined in IAS 28.

Foreign currencies
Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates ('functional currency'). The Group's financial statements are presented in US Dollars, the currency which the Group has elected to use as its presentation currency.

In the financial statements of the Company and its individual subsidiaries, transactions in currencies other than a company's functional currency are recorded at the prevailing rate of exchange on the date of the transaction. At the year end, monetary assets and liabilities denominated in foreign currencies are retranslated at the rates of exchange prevailing at the balance sheet date. Non-monetary assets and liabilities that are measured at historical cost in a foreign currency are translated using the rate of exchange at the dates of the initial transactions. Non-monetary assets and liabilities measured at fair value in a foreign currency are translated using the rate of exchange at the date the fair value was determined. All foreign exchange gains and losses are taken to profit and loss in the Group income statement.

Emissions liabilities
The Group operates in an energy intensive industry and is therefore required to partake in emission trading schemes ('ETS'). The Group recognises an emission liability in line with the production of emissions that give rise to the obligation. To the extent the liability is covered by allowances held, the liability is recognised at the cost of these allowances held and if insufficient allowances are held, the remaining uncovered portion is measured at the spot market price of allowances at the balance sheet date. The expense is presented within 'production costs' under 'cost of sales' and the accrual is presented in 'trade and other payables'. Any allowance purchased to settle the Group's liability is recognised on the balance sheet as an intangible asset. Both the emission allowances and the emission liability are derecognised upon settling the liability with the respective regulator.

Use of judgements, estimates and assumptions
The preparation of the Group's consolidated financial statements requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, at the date of the

consolidated financial statements. Estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

The accounting judgements and estimates that have a significant impact on the results of the Group are set out below and should be read in conjunction with the information provided in the Notes to the financial statements. The Group does not consider contingent consideration and deferred taxation (including EPL) to represent a significant estimate or judgement as the estimates and assumptions relating to projected earnings and cash flows used to assess contingent consideration and deferred taxation are the same as those applied in the Group impairment process as described below in *Recoverability of asset carrying values*. Judgements and estimates, not all of which are significant, made in assessing the impact of climate change and the transition to a lower carbon economy on the consolidated financial statements are also set out below. Where an estimate has a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year, this is specifically noted.

Climate change and energy transition
As covered in the Group's principal risks on oil and gas prices on page 22, the Group recognises that the energy transition is likely to impact the demand, and hence the future prices, of commodities such as oil and natural gas. This in turn may affect the recoverable amount of property, plant and equipment and goodwill, valuation of contingent consideration and deferred tax, as well as an acceleration of cessation of production and subsequent decommissioning expenditure, in the oil and gas industry. 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 natural gas and their impact on the Group's long-term price assumptions. See *Recoverability of asset carrying values: Oil prices*.

While the pace of transition to a lower carbon economy is uncertain, oil and natural gas demand is expected to remain a key element of the energy mix for many years 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, a material adverse change is not expected to the carrying values of EnQuest's assets and liabilities within the next financial year as a result of climate change and the transition to a lower carbon economy.

Management will continue to review price assumptions as the energy transition progresses and this may result in impairment charges or reversals in the future.

Critical accounting judgements and key sources of estimation uncertainty
The Group has considered its critical accounting judgements and key sources of estimation uncertainty, and these are set out below.

Recoverability of asset carrying values
Judgements: The Group assesses each asset or cash-generating unit ('CGU') (excluding goodwill, which is assessed annually regardless of indicators) in each reporting period to determine whether any indication of impairment exists. Assessment of indicators of impairment or impairment reversal and the determination of the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment purposes require significant management judgement. For example, individual oil and gas properties may form separate CGUs, whilst certain oil and gas properties with shared infrastructure may be grouped together to form a single CGU. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing. See note 10 for details on how these groupings have been determined in relation to the impairment testing of goodwill.

Estimates: Where an indicator of impairment exists, a formal estimate of the recoverable amount is made, which is considered to be the higher of the fair value less costs to dispose ('FVLCD') and value in use ('VIU'). The assessments require the use of estimates and assumptions, such as the effects of inflation and deflation on operating expenses, cost profile changes including those related to emission reduction initiatives such as alternative fuel provision at Kraken, discount rates, capital expenditure, production profiles, reserves and resources, and future commodity prices, including the outlook for global or regional market supply-and-demand conditions for crude oil and natural gas. Such estimates reflect management's best estimate of the related cash flows based on management's plans for the assets and their future development.

As described above, the recoverable amount of an asset is the higher of its VIU and its FVLCD. When the recoverable amount is measured by reference to FVLCD, in the absence of quoted market prices or binding sale agreement, estimates are made regarding the present value of future post-tax cash flows. These estimates are made from the perspective of a market participant and include prices, life of field production profiles based on reserves and resources to which it is considered probable that a market participant would attribute value to them, operating costs, capital expenditure, decommissioning costs, tax attributes, risking factors applied to cash flows, and discount rates.

Details of impairment charges and reversals recognised in the income statement and details on the carrying amounts of assets are shown in note 9, note 10 and note 11.

The estimates for assumptions made in impairment tests in 2024 relating to discount rates and oil prices are discussed below. Changes in the economic environment or other facts and circumstances may necessitate revisions to these assumptions and could result in a material change to the carrying values of the Group's assets within the next financial year.

Discount rates
For discounted cash flow calculations, future cash flows are adjusted for risks specific to the CGU. FVLCD discounted cash flow calculations use the post-tax discount rate. The discount rate is derived using the weighted average cost of capital methodology. The discount rates applied in impairment tests are reassessed each year and, in 2024, the post-tax discount rate was estimated at 10.0% (2023: 11.0%) reflecting the impact from the Group's reduced debt position and clarity over the UK fiscal system.

Oil prices
The price assumptions used for FVLCD impairment testing were based on latest internal forecasts as at 31 December 2024. These price forecasts reflect EnQuest's views of global supply and demand, including the potential financial impacts on the Group of climate change and the transition to a low carbon economy as outlined in the Basis of Preparation, and are benchmarked with external sources of information such as analyst forecasts. The Group's price forecasts are reviewed and approved by management, the Audit Committee and the Board of Directors.

EnQuest revised its oil price assumptions for FVLCD impairment testing compared to those used in 2023, with nearer-term prices reflecting current market dynamics and external forecasts. A summary of the Group's revised price assumptions is provided below. These assumptions, which represent management's best estimate of future prices, sit within the range of external forecasts. When compared to the International Energy Agency's ('IEA') forecast prices under its Announced Pledges Scenario ('APS'), which assumes all climate commitments made by governments and industries around the world by the end of August 2024 for both 2030 targets and longer-term net zero or carbon neutrality pledges will be met in full and on time, EnQuest's short and medium-term assumptions are below those assumed under the APS, while its longer-term prices are slightly higher. When compared with latest available Paris-consistent climate scenario modelling data released by the World Business Council of Sustainable Development ('WBCSD'), EnQuest's assumption is broadly aligned with the top end of a range of Paris-consistent scenarios. A 10% reduction in crude oil price assumptions, which management believes to be a reasonably possible change as further considered later in this note, is comfortably within the range of WBCSD Paris-consistent scenarios. Discounts or premiums are applied to price assumptions based on the characteristics of the oil produced and the terms of the relevant sales contracts.

An inflation rate of 2% (2023: 2%) is applied from 2028 onwards to determine the price assumptions in nominal terms (see table below).

The price assumptions used in 2023 were $80.0/bbl (2024), $80.0/bbl (2025), $75.0/bbl (2026) and $77.0/bbl real thereafter, inflated at 2.0% per annum from 2027.

	2025	2026	2027	2028>*
Brent oil ($/bbl)	75.0	75.0	75.0	77.0

- Inflated at 2% from 2028

Oil and natural gas reserves
Hydrocarbon reserves are estimates of the amount of hydrocarbons that can be economically and legally extracted from the Group's oil and gas properties. The business of the Group is to responsibly optimise production, leverage existing infrastructure, deliver a strong decommissioning performance and explore new energy and decarbonisation opportunities. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity, and drilling of new wells all impact on the determination of the Group's estimates of its oil and gas reserves and result in different future production profiles affecting prospectively the discounted cash flows used in impairment testing and the calculation of contingent consideration, the anticipated date of decommissioning and the depletion charges in accordance with the unit of production method, as well as the going concern assessment. Economic assumptions used to estimate reserves change from period to period as additional technical and operational data is generated. This process may require complex and difficult geological judgements to interpret the data.

The Group uses proven and probable ('2P') reserves (see page 18) and, for the Kraken CGU, 2C resources associated with the Bressay gas well as an alternative fuel provision for the Kraken FPSO as the basis for calculations of expected future cash flows from underlying assets because this represents the reserves and resources management intends to develop and it is probable that a market participant would attribute value to them. Third-party audits of EnQuest's reserves and resources are conducted annually.

Sensitivity analyses
Changes in price and its consequential impact on impairment, contingent consideration and deferred tax along with the discount rate impact on impairment and decommissioning are considered to be the only key sources of estimation uncertainty, although other sensitivities that the Group believes are useful for users of these accounts but are not considered to have a significant risk of resulting in material changes to carrying amounts in the next 12 months, may also be provided.

Management tested the impact of a change in cash flows in FVLCD impairment testing arising from a 10% reduction in crude price assumptions, which it believes to be a reasonably possible change given the prevailing macroeconomic environment.

Price reductions of this magnitude in isolation could indicatively lead to a further reduction in the carrying amount of EnQuest's oil and gas properties by approximately $221.6 million, which is approximately 10% of the net book value of property, plant and equipment as at 31 December 2024.

The oil price sensitivity analysis above does not, however, represent management's best estimate of any impairments that might be recognised as it does 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 the extent of a price reduction increases, the more likely it is 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 percentage point change in the discount rate of 10.0% used for FVLCD impairment testing of oil and gas properties, which is considered a reasonably possible change given the prevailing macroeconomic environment. If the discount rate was one percentage point higher across all tests performed, the net impairment charge in 2024 would have been approximately $51.2 million higher. If the discount rate was one percentage point lower, the net impairment charge would have been approximately $55.9 million lower.

Goodwill
Irrespective of whether there is any indication of impairment, EnQuest is required to test annually for impairment of goodwill acquired in business combinations. The Group carries goodwill of approximately $134.4 million on its balance sheet (2023: $134.4 million), principally relating to the acquisition of Magnus oil field. Sensitivities and additional information relating to impairment testing of goodwill are provided in note 10.

Deferred tax
The Group assesses the recoverability of its deferred tax assets at each period end. Sensitivities and additional information relating to deferred tax assets/liabilities are provided in note 6(d).

75% Magnus acquisition contingent consideration
Estimates: The Group reassessed the fair value discount rate associated with the Magnus contingent consideration and estimated it to be 11.3% as at the end of 2024 (2023: 11.3%), as calculated in line with IFRS 13. Sensitivities and additional information relating to the 75% Magnus acquisition contingent consideration are provided in note 21.

Provisions

Estimates: Decommissioning costs will be incurred by the Group at the end of the operating life of some of the Group's oil and gas production facilities and pipelines. The Group assesses its decommissioning provision at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal requirements, estimates of the extent and costs of decommissioning activities, the emergence of new restoration techniques and experience at other production sites. The expected timing, extent and amount of expenditure may also change, for example, in response to changes in oil and gas reserves or changes in laws and regulations or their interpretation. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning. As a result, there could be significant adjustments to the provisions established which would affect future financial results.

The timing and amount of future expenditures relating to decommissioning and environmental liabilities are reviewed annually. The rate used in discounting the cash flows is reviewed half-yearly. The nominal discount rate used to determine the balance sheet obligations at the end of 2024 was 4.5% (2023: 3.5%), reflecting the UK Gilt interest rate environment. The weighted average period over which decommissioning costs are generally expected to be incurred is estimated to be approximately 13 years. Costs at future prices are determined by applying inflation rates at 2.0% per annum thereafter (2023: 2.5% (2024) and a long-term inflation rate of 2% thereafter) to decommissioning costs.

Further information about the Group's provisions is provided in note 22. Changes in assumptions could result in a material change in their carrying amounts within the next financial year. A one percentage point decrease in the nominal discount rate applied, which is considered a reasonably possible change given the prevailing macroeconomic environment, could increase the Group's provision balances by approximately $59.4 million (2023: $68.0 million). The pre-tax impact on the Group income statement would be a charge of approximately $58.7 million (2023: $67.1 million).

3. Segment information

The Group's organisational structure reflects the various activities in which EnQuest is engaged. Management has considered the requirements of IFRS 8 Operating Segments in regard to the determination of operating segments and concluded that at 31 December 2024, the Group had two significant operating segments: the North Sea and Malaysia. Operations are managed by location and all information is presented per geographical segment. The Group's segmental reporting structure remained in place throughout 2024. The North Sea's activities include Upstream, Midstream, Decommissioning and Veri Energy. Veri Energy is not considered a separate operating segment as it does not yet earn revenues and is not yet a material part of the Group from a capital and human resources allocation perspective. Malaysia's activities include Upstream and Decommissioning. The Group's reportable segments may change in the future depending on the way that resources may be allocated and performance assessed by the Chief Operating Decision Maker, who for EnQuest is the Chief Executive. The information reported to the Chief Operating Decision Maker does not include an analysis of assets and liabilities, and accordingly this information is not presented, in line with IFRS 8 paragraph 23.

Year ended 31 December 2024 $'000	**North Sea**	**Malaysia**	**All other segments**	**Total segments**	**Adjustments and eliminations(i), (iii)**	**Consolidated**
Revenue and other operating income:						
Revenue from contracts with customers	**1,063,829**	**123,728**	**–**	**1,187,557**	**–**	**1,187,557**
Other operating income/(expense)	**2,709**	**–**	**260**	**2,969**	**(9,817)**	**(6,848)**
Total revenue and other operating income/(expense)	**1,066,538**	**123,728**	**260**	**1,190,526**	**(9,817)**	**1,180,709**
Income/(expenses) line items:						
Depreciation and depletion	**(252,208)**	**(17,042)**	**(41)**	**(269,291)**	**–**	**(269,291)**
Net impairment (charge)/reversal to oil and gas assets	**(71,414)**	**–**	**–**	**(71,414)**	**–**	**(71,414)**
Exploration write-off and impairments	**–**	**(183)**	**–**	**(183)**	**–**	**(183)**
Segment profit/(loss)(ii), (iii)	**274,354**	**45,536**	**9,013**	**328,903**	**(17,375)**	**311,528**
Other disclosures:						
Capital expenditure(iv)	**313,557**	**32,774**	**15**	**346,346**	**–**	**346,346**

Year ended 31 December 2023 $'000	North Sea	Malaysia	All other segments	Total segments	Adjustments and eliminations(i), (iii)	Consolidated
Revenue and other operating income:						
Revenue from contracts with customers	1,325,200	142,510	–	1,467,710	–	1,467,710
Other operating income/(expense)	2,229	–	281	2,510	17,199	19,709
Total revenue and other operating income/(expense)	1,327,429	142,510	281	1,470,220	17,199	1,487,419
Income/(expenses) line items:						
Depreciation and depletion	(278,280)	(19,923)	(105)	(298,308)	–	(298,308)
Net impairment (charge)/reversal to oil and gas assets	(117,396)	–	–	(117,396)	–	(117,396)
Exploration write-off and impairments	–	(5,640)	–	(5,640)	–	(5,640)
Segment profit/(loss)(ii), (iii)	330,501	46,192	4,474	381,167	16,206	397,373
Other disclosures:						
Capital expenditure(iv)	149,093	11,817	12	160,922	–	160,922

(i) Finance income and costs and gains and losses on derivatives are not allocated to individual segments as the underlying instruments are managed on a Group basis

(ii) Tax is not included as this is not disclosed to the Chief Operating Decision Maker within the segment profit/(loss)

(iii) Inter-segment revenues are eliminated on consolidation. All other adjustments are part of the reconciliations presented further below

(iv) Capital expenditure consists of property, plant and equipment and intangible exploration and appraisal assets

Reconciliation of profit/(loss):

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Segment profit/(loss) before tax and finance income/(costs)	**328,903**	381,167
Finance costs	**(159,422)**	(172,087)
Finance income	**14,508**	6,493
(Loss)/gain on derivatives(i)	**(17,375)**	16,206
Profit/(loss) before tax	**166,614**	231,779

(i) Includes $17.6 million realised losses on derivatives (2023: $8.4 million) and $0.3 million unrealised gains on derivatives (2023: $24.6 million). See note 18(b) for further detail

Revenue from three customers relating to the North Sea operating segment each exceeds 10% of the Group's consolidated revenue arising from sales of crude oil, with amounts of $394.8 million, $156.0 million and $115.7 million per each single customer (2023: two customers; $491.2 million and $201.3 million per each single customer).

4. Revenue and expenses

(a) Revenue and other operating income

Accounting policy

Revenue from contracts with customers

The Group generates revenue through the sale of crude oil, gas and condensate to third parties, and through the provision of infrastructure to its customers for tariff income. Revenue from contracts with customers is recognised when control of the goods or services is transferred to the customer at an amount that reflects the consideration to which the Group expects to be entitled in exchange for those goods or services. The Group has concluded that it is the principal in its revenue arrangements because it typically controls the goods or services before transferring them to the customer. The normal credit term is 30 days or less upon performance of the obligation.

Sale of crude oil, gas and condensate

The Group sells crude oil, gas and condensate directly to customers. The sale represents a single performance obligation, being the sale of barrels equivalent to the customer on taking physical possession or on delivery of the commodity into an infrastructure. At this point the title passes to the customer and revenue is recognised. The Group principally satisfies its performance obligations at a point in time; the amounts of revenue recognised relating to performance obligations satisfied over time are not significant. Transaction prices are referenced to quoted prices, plus or minus an agreed fixed premium or discount rate to an appropriate benchmark, if applicable.

Tariff revenue for the use of Group infrastructure

Tariffs are charged to customers for the use of infrastructure owned by the Group. The revenue represents the performance of an obligation for the use of Group assets over the life of the contract. The use of the assets is not separable as they are interdependent in order to fulfil the contract and no one item of infrastructure can be individually isolated. Revenue is recognised as the performance obligations are satisfied over the period of the contract, generally a period of 12 months or less, on a monthly basis based on throughput at the agreed contracted rates.

Other operating income

Other operating revenue is recognised to the extent that it is probable economic benefits will flow to the Group and the revenue can be reliably measured.

The Group enters into commodity derivative trading transactions which can be settled net in cash. Accordingly, any gains or losses are not considered to constitute revenue from contracts with customers in accordance with the requirements of IFRS 15, rather are accounted for in line with IFRS 9 and included within other operating income (see note 18).

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Revenue from contracts with customers:		
Revenue from crude oil sales	**1,020,266**	1,127,419
Revenue from gas and condensate sales(i)	**164,647**	338,973
Tariff revenue	**2,644**	1,318
Total revenue from contracts with customers	**1,187,557**	1,467,710
Realised (losses)/gains on commodity derivative contracts (see note 18)	**(12,907)**	(11,264)
Unrealised gains/(losses) on commodity derivative contracts (see note 18)	**3,090**	28,463
Other	**2,969**	2,510
Total revenue and other operating income	**1,180,709**	1,487,419

(i) Includes onward sale of third-party gas purchases not required for injection activities at Magnus (see note 4(b))

Disaggregation of revenue from contracts with customers

	Year ended 31 December 2024 $'000			Year ended 31 December 2023 $'000		
	North Sea	**Malaysia**	**Total**	North Sea	Malaysia	Total
Revenue from contracts with customers:						
Revenue from crude oil sales	**900,310**	**119,956**	**1,020,266**	987,610	139,809	1,127,419
Revenue from gas and condensate sales(i)	**162,951**	**1,696**	**164,647**	336,902	2,071	338,973
Tariff revenue	**568**	**2,076**	**2,644**	689	629	1,318
Total revenue from contracts with customers	**1,063,829**	**123,728**	**1,187,557**	1,325,201	142,509	1,467,710

(i) Includes onward sale of third-party gas purchases not required for injection activities at Magnus (see note 4(b))

(b) Cost of sales

Accounting policy

Production imbalances, movements in under/over-lift and movements in inventory are included in cost of sales. The over-lift liability is recorded at the cost of the production imbalance to represent a provision for production costs attributable to the volumes sold in excess of entitlement. The under-lift asset is recorded at the lower of cost and net realisable value ('NRV'), consistent with IAS 2, to represent a right to additional physical inventory. An under-lift of production from a field is included in current receivables and an over-lift of production from a field is included in current liabilities.

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Production costs	**307,634**	308,331
Tariff and transportation expenses	**70,449**	41,736
Realised loss/(gain) on derivative contracts related to operating costs (see note 18)	**4,735**	(2,839)
Unrealised losses/(gains) on derivative contracts related to operating costs (see note 18)	**2,823**	3,832
Change in lifting position	**3,528**	(2,669)
Crude oil inventory movement	**(1,356)**	(1,575)
Depletion of oil and gas assets(i)	**263,251**	292,199
Movement in contractor dispute provision	**–**	1,818
Other cost of operations(ii)	**136,319**	305,919
Total cost of sales	**787,383**	946,752

(i) Includes $27.9 million (2023: $28.6 million) Kraken FPSO right-of-use asset depreciation charge and $23.5 million (2023: $24.0 million) of other right-of-use assets depreciation charge
(ii) Includes $125.7 million (2023: $294.0 million) of purchases and associated costs of third-party gas not required for injection activities at Magnus, which is sold on

(c) General and administration expenses

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Staff costs (see note 4(e))	**75,833**	77,517
Depreciation(i)	**6,040**	6,109
Other general and administration costs	**26,748**	25,490
Recharge of costs to operations and joint venture partners	**(102,919)**	(102,768)
Total general and administration expenses	**5,702**	6,348

(i) Includes $3.4 million (2023: $3.4 million) right-of-use assets depreciation charge on buildings

(d) Other (expenses)/income

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Net foreign exchange gains/(losses)	**9,975**	(11,659)
Rental income from office sublease	**2,201**	2,286
Fair value changes in contingent consideration (see note 21)[(i)]	**(15,904)**	10,811
Change in decommissioning provisions (see note 22)	**(6,666)**	(31,159)
Change in Thistle decommissioning provision (see note 22)	**(412)**	(1,605)
Drilling rig contract cancellation costs[(ii)]	**(14,629)**	–
Unsuccessful exploration expenditure (see note 11)	**(183)**	(5,640)
Insurance income	**1,663**	4,127
Reversal of provisions	–	101
Other	**19,273**	13,188
Total other (expenses)/income	**(4,682)**	(19,550)

(i) In previous periods, the element of the movement in the fair value of the Magnus contingent consideration due to the passage of time ("unwinding of discount") has been recorded within finance costs, with remaining fair value movements recorded within other income or expense. Following a review of this presentation and comparing this to market practice, it has been concluded that it would be more appropriate for the impact from both the unwind of discount and other changes in fair value to be combined within other income/expense, with comparative information restated. This restatement results in a $58.9 million charge for 2023 being reclassified from finance costs to other income/expense, with no impact on net income or closing retained earnings for that year

(ii) Drilling rig contract at Kraken was terminated due to a deferral of infill drilling

(e) Staff costs

Accounting policy

Short-term employee benefits, such as salaries, social premiums and holiday pay, are expensed when incurred.

The Group's pension obligations consist of defined contribution plans. The Group pays fixed contributions with no further payment obligations once the contributions have been paid. The amount charged to the Group income statement in respect of pension costs reflects the contributions payable in the year. Differences between contributions payable during the year and contributions actually paid are shown as either accrued liabilities or prepaid assets in the balance sheet.

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Wages and salaries	**66,700**	63,458
Social security costs	**5,899**	5,457
Defined contribution pension costs	**5,265**	5,038
Expense of share-based payments (see note 20)	**983**	3,320
Other staff costs	**12,300**	11,079
Total employee costs	**91,147**	88,352
Contractor costs	**37,493**	38,304
Total staff costs	**128,640**	126,656
General and administration staff costs (see note 4(c))	**75,833**	77,517
Non-general and administration costs	**52,807**	49,139
Total staff costs	**128,640**	126,656

The monthly average number of persons, excluding contractors, employed by the Group during the year was 673, with 336 in the general and administration staff costs and 337 directly attributable to assets (2023: 697 of which 343 in general and administration and 354 directly attributable to assets). Compensation of key management personnel is disclosed in note 26.

(f) Auditor's remuneration

The following amounts for the year ended 31 December 2024 and for the comparative year ended 31 December 2023 were payable by the Group to Deloitte:

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Fees payable to the Company's auditor for the audit of the parent company and Group financial statements	**1,367**	1,239
The audit of the Company's subsidiaries	**173**	149
Total audit	**1,540**	1,388
Audit-related assurance services(i)	**589**	314
Total audit and audit-related assurance services	**2,129**	1,702
Total auditor's remuneration	**2,129**	1,702

(i) Audit-related assurance services in both years include the review of the Group's interim results, G&A assurance review and the provision of customary comfort letters in respect of the debt refinancing

5. Finance costs/income

Accounting policy

Borrowing costs are recognised as interest payable within finance costs at amortised cost using the effective interest method.

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Finance costs:		
Loan interest payable	**18,524**	30,708
Bond interest payable	**54,971**	58,999
Unwinding of discount on decommissioning provisions (see note 22)	**30,290**	24,236
Unwinding of discount on other provisions (see note 22)	**911**	1,145
Debt refinancing fees (see note 17)	**4,809**	–
Finance charges payable under leases (see note 23)	**27,673**	43,801
Finance fees on loans and bonds including amortisation of capitalised fees	**14,473**	7,899
Other financial expenses(i)	**7,771**	5,299
Total finance costs	**159,422**	172,087
Finance income:		
Bank interest receivable	**11,110**	6,493
RockRose loan interest (see note 18(f))	**3,263**	–
Other financial income	**135**	–
Total finance income	**14,508**	6,493

(i) 2023 includes unwinding of discount on Golden Eagle contingent consideration of $1.7 million. See note 21

6. Income tax

(a) Income tax

Accounting policy

Current tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities, based on tax rates and laws that are enacted or substantively enacted by the balance sheet date.

The Group's operations are subject to a number of specific tax rules which apply to exploration, development and production. In addition, the tax provision is prepared before the relevant companies have filed their tax returns with the relevant tax authorities and, significantly, before these have been agreed. As a result of these factors, the tax provision process necessarily involves the use of a number of estimates and judgements, including those required in calculating the effective tax rate.

Deferred tax is provided in full on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the Group financial statements. However, deferred tax is not accounted for if a temporary difference arises from initial recognition of other assets or liabilities in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss. Deferred tax is measured on an undiscounted basis using tax rates (and laws) that have been enacted or substantively enacted by the balance sheet date and are expected to apply when the related deferred tax asset is realised or the deferred tax liability is settled. Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilised.

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.

The carrying amount of deferred income tax assets is reviewed at each balance sheet date. Deferred income tax assets and liabilities are offset only if a legal right exists to offset current tax assets against current tax liabilities, the deferred income taxes relate to the same taxation authority and that the Group intends to make a single net payment.

Production taxes

In addition to corporate income taxes, the Group's financial statements also include and disclose production taxes on net income determined from oil and gas production.

Production tax relates to Petroleum Revenue Tax ('PRT') within the UK and is accounted for under IAS 12 Income Taxes since it has the characteristics of an income tax as it is imposed under government authority and the amount payable is based on taxable profits of the relevant fields. Current and deferred PRT is provided on the same basis as described above for income taxes.

Investment allowance

The UK taxation regime provides for a reduction in ring-fence supplementary charge tax where investment in new or existing UK assets qualify for a relief known as investment allowance. Investment allowance must be activated by commercial production from the same field before it can be claimed. The Group has both unactivated and activated investment allowances which could reduce future supplementary charge taxation. The Group's policy is that investment allowance is recognised as a reduction in the charge to taxation in the years claimed.

Energy Profits Levy

The Energy (Oil & Gas) Profits Levy Act 2022 ('EPL') applies an additional tax on the profits earned by oil and gas companies from the production of oil and gas on the United Kingdom Continental Shelf until 31 March 2028. This is accounted for under IAS 12 Income Taxes since it has the characteristics of an income tax as it is imposed under government authority and the amount payable is based on taxable profits of the relevant UK companies. Current and deferred tax is provided on the same basis as described above for income taxes.

The major components of income tax expense/(credit) are as follows:

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Current UK income tax		
Current income tax charge	**–**	–
Adjustments in respect of current income tax of previous years	**–**	(14)
Current overseas income tax		
Current income tax charge	**11,432**	24,685
Adjustments in respect of current income tax of previous years	**(746)**	(2,567)
UK Energy Profits Levy		
Current year charge	**10,262**	175,118
Adjustments in respect of current charge of previous years	**(8,803)**	(11,605)
Total current income tax	**12,145**	185,617
Deferred UK income tax		
Relating to origination and reversal of temporary differences	**42,745**	160,712
Adjustments in respect of deferred income tax of previous years	**(9,103)**	4,974
Deferred overseas income tax		
Relating to origination and reversal of temporary differences	**7,071**	(3,761)
Adjustments in respect of deferred income tax of previous years	**31**	1,430
Deferred UK Energy Profits Levy		
Relating to origination and reversal of temporary differences	**11,156**	(58,661)
Adjustments in respect of changes in tax rates	**6,889**	–
Adjustments in respect of deferred charge of previous years	**1,907**	(27,699)
Total deferred income tax	**60,696**	76,995
Income tax expense reported in profit or loss	**72,841**	262,612

(b) Reconciliation of total income tax charge

A reconciliation between the income tax charge and the product of accounting profit multiplied by the UK statutory tax rate is as follows:

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Profit/(loss) before tax	**166,614**	231,779
UK statutory tax rate applying to North Sea oil and gas activities of 40% (2023: 40%)	**66,646**	92,712
Supplementary corporation tax non-deductible expenditure	**5,809**	10,580
Non-deductible expenditure(i)	**26,114**	69,494
Non-taxable gain on sale of assets	**505**	–
Petroleum revenue tax (net of income tax benefit)	**(8,938)**	(8,200)
Tax in respect of non-ring-fence trade	**7,298**	7,418
Deferred tax asset not recognised in respect of non-ring-fence trade	**12,243**	11,696
Deferred tax asset recognised on previously unrecognised losses	**(48,115)**	–
UK Energy Profits Levy(ii)	**(13,921)**	116,457
UK Energy Profits Levy – changes in tax rates(ii)	**6,889**	–
UK Energy Profits Levy – abolishment of Investment Allowance(ii)	**35,339**	–
Adjustments in respect of prior years	**(16,713)**	(35,481)
Overseas tax rate differences	**2,045**	(1,114)
Share-based payments	**(1,407)**	(90)
Other differences	**(953)**	(860)
At the effective income tax rate of 44% (2023: 113%)	**72,841**	262,612

(i) Predominantly in relation to non-qualifying expenditure relating to the initial recognition exemption utilised under IAS 12 upon acquisition of Golden Eagle given that at the time of the transaction, it affected neither accounting profit nor taxable profit

(ii) Total current year EPL charge only. This consists of an EPL current tax charge of $10.3 million (2023: $175.1 million charge) and deferred EPL charge of $18.0 million (2023: $58.7 million credit). The impact of the substantially enacted Autumn Statement changes referred to in part (e) below are included within these amounts and have been disclosed separately above

(c) Deferred income tax

Deferred income tax relates to the following:

	Group balance sheet		Charge/(credit) for the year recognised in profit or loss	
	2024 $'000	2023 $'000	**2024 $'000**	2023 $'000
Deferred tax liability				
Accelerated capital allowances	**911,501**	877,800	**33,701**	(86,015)
	911,501	877,800		
Deferred tax asset				
Losses	**(717,900)**	(695,888)	**(22,012)**	206,213
Decommissioning liability	**(263,705)**	(265,800)	**2,095**	(27,176)
Other temporary differences(i)	**(331,679)**	(378,591)	**46,912**	(16,027)
	(1,313,284)	(1,340,279)	**60,696**	76,995
Net deferred tax (assets)(ii)	**(401,783)**	(462,479)		
Reflected in the balance sheet as follows:				
Deferred tax assets	**(506,481)**	(540,122)		
Deferred tax liabilities	**104,698**	77,643		
Net deferred tax (assets)	**(401,783)**	(462,479)		

(i) Predominantly includes $199.2 million related to Magnus acquisition contingent consideration in note 21 and $107.7 million on deferred income in note 24

(ii)The total amounts for EPL included in net deferred assets are $160.7 million for accelerated capital allowances and $73.4 million for other items, which predominantly includes $18.7 million Magnus acquisition contingent consideration (note 21) and $52.5 million deferred income (note 24)

Reconciliation of net deferred tax assets/(liabilities)

	2024 $'000	2023 $'000
At 1 January	**462,479**	539,474
Tax expense during the period recognised in profit or loss	**(60,696)**	(76,995)
At 31 December	**401,783**	462,479

(d) Tax losses

The Group's deferred tax assets at 31 December 2024 are recognised to the extent that taxable profits are expected to arise in the future against which tax losses and allowances in the UK can be utilised. In accordance with IAS 12 Income Taxes, the Group assesses the recoverability of its deferred tax assets at each period end. 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 (see note 2). A 10% reduction in oil price would result in a deferred tax asset derecognition of $62.1 million while a 10% increase in oil price would not result in any change as the Group is currently recognising all UK tax losses (with the exception of those noted below).

The Group has unused UK mainstream corporation tax losses of $496.1 million (2023: $442.1 million) and ring-fence tax losses of $1,117.5 million (2023: $1,163.0 million) associated with the Bentley acquisition, for which no deferred tax asset has been recognised at the balance sheet date as of recovery of these losses is to be established. In addition, the Group has not recognised a deferred tax asset for the adjustment to bond valuations on the adoption of IFRS 9. The benefit of this deduction is taken over ten years, with a deduction of $2.2 million being taken in the current period and the remaining benefit of $6.3 million (2023: $8.5 million) remaining unrecognised.

The Group has unused Malaysian income tax losses of $14.7 million (2023: $14.3 million) arising in respect of the Tanjong Baram RSC for which no deferred tax asset has been recognised at the balance sheet date due to uncertainty of recovery of these losses.

No deferred tax has been provided on unremitted earnings of overseas subsidiaries. The Finance Act 2009 exempted foreign dividends from the scope of UK corporation tax where certain conditions are satisfied.

(e) Changes in legislation

In June 2023, the UK introduced legislation implementing the Organisation for Economic Co-operation and Development's ('OECD') proposals for a global minimum corporation tax rate (Pillar Two) which is effective for periods beginning on or after 31 December 2023. This legislation will ensure that profits earned internationally are subject to a minimum tax rate of 15%. The Group has performed an assessment of the exposure to Pillar Two income taxes from 1 January 2024 and it does not have an exposure to Pillar Two income taxes in any jurisdictions. The Group has applied the mandatory exception to recognising and disclosing information about the deferred tax assets and liabilities related to Pillar Two income taxes in accordance with the amendments to IAS 12 published by the International Accounting Standards Board ('IASB') on 23 May 2023.

In the Autumn Statement on 22 November 2023, the UK Government confirmed that it will bring in legislation for the Energy Security Investment Mechanism ('ESIM') which would remove the EPL if both average oil and gas prices fall to, or below, $71.40 per barrel for oil and £0.54 per therm for gas, for two consecutive quarters, and agreed to index link the trigger floor price to the CPI from April 2024. From April 2024, the ESIM threshold prices were revised to $74.21 per barrel for oil and £0.57 per therm for gas. EnQuest does not currently forecast that the floor price will be met for both oil and gas prices and therefore there is currently no impact from this on tax carrying values.

In the Autumn Statement on 30 October 2024, the UK Government confirmed that from 1 November 2024 the rate of Energy Profits Levy ('EPL') would be increased from 35% to 38%. They also announced that the EPL Investment Allowance would be abolished from 1 November 2024 (although First Year Allowances would be retained) and decarbonisation relief would be reduced from 80% to 66%. The impact of these changes on the current year financial statements is an increase in the tax charge and deferred tax for EPL of $42.2 million. The announcement to extend the EPL period to 31 March 2030 was not substantively enacted at 31 December 2024 and therefore is not included in the tax balances included in these financial statements. It is expected that this extension, which was substantively enacted on 3 March 2025, will result in the recognition of an additional deferred tax liability of approximately $115.9 million.

7. Earnings per share

The calculation of basic earnings per share is based on the profit after tax and on the weighted average number of Ordinary shares in issue during the period. Diluted earnings per share is adjusted for the effects of Ordinary shares granted under the share-based payment plans, which are held in the Employee Benefit Trust, unless it has the effect of increasing the profit or decreasing the loss attributable to each share.

During the year to 31 December 2024, the Group repurchased 55,894,836 Ordinary shares, of which 25,000,000 ordinary shares have been classified in the balance sheet as Treasury shares with the balance cancelled (see note 8). The Treasury shares have been excluded for the purposes of calculating the basic and diluted earnings per share at 31 December 2024.

Basic and diluted earnings per share are calculated as follows:

	Profit/(loss) after tax		Weighted average number of Ordinary shares		Earnings per share	
	Year ended 31 December		Year ended 31 December		Year ended 31 December	
	2024 $'000	2023 $'000	**2024 million**	2023 million	**2024 $**	2023 $
Basic	**93,773**	(30,833)	**1,891.9**	1,871.9	**0.050**	(0.016)
Dilutive potential of Ordinary shares granted under share-based incentive schemes	**–**	–	**24.3**	32.4	**(0.001)**	–
Diluted(i)	**93,773**	(30,833)	**1,916.2**	1,904.3	**0.049**	(0.016)

(i) Potential Ordinary shares are not treated as dilutive when they would decrease a loss per share and as a result the weighted average number of Ordinary shares used as the denominator in the calculation of diluted EPS is the same as that used for calculating basic EPS in 2023.

8. Distributions paid and proposed

The Company paid no dividends during the year ended 31 December 2024 (2023: none). At 31 December 2024, there were no proposed dividends (2023: none). During 2024, a share buyback programme was executed with a total of 55,894,836 shares ($9.0 million) repurchased as at 31 December 2024.

Having continued to reduce EnQuest net debt and optimise the debt structure, EnQuest is now positioned to balance deploying capital for growth and returns to shareholders. As such, the Board is pleased to propose a final ordinary dividend of 0.616 pence per share (equivalent to c.$15 million). This final dividend is subject to approval by shareholders at the Annual General Meeting on 27 May 2025 and so not recognised as a liability as at 31 December 2024. If approved, the dividend will be paid on 6 June 2025 to shareholders on the register at 2 May 2025. Shares will trade ex-dividend from 1 May 2025.

9. Property, plant and equipment

Accounting policy

Property, plant and equipment is stated at cost less accumulated depreciation and accumulated impairment charges.

Cost

Cost comprises the purchase price or cost relating to development, including the construction, installation and completion of infrastructure facilities such as platforms, pipelines and development wells and any other costs directly attributable to making that asset capable of operating as intended by management. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

The carrying amount of an item of property, plant and equipment is derecognised on disposal or when no future economic benefits are expected from its use. The gain or loss arising from the derecognition of an item of property, plant and equipment is included in the other operating income or expense line item in the Group income statement when the asset is derecognised.

Development assets

Expenditure relating to development of assets, including the construction, installation and completion of infrastructure facilities such as platforms, pipelines and development wells, is capitalised within property, plant and equipment.

Carry arrangements

Where amounts are paid on behalf of a carried party, these are capitalised. Where there is an obligation to make payments on behalf of a carried party and the timing and amount are uncertain, a provision is recognised. Where the payment is a fixed monetary amount, a financial liability is recognised.

Borrowing costs

Borrowing costs directly attributable to the construction of qualifying assets, which are assets that necessarily take a substantial period of time to prepare for their intended use, are capitalised during the development phase of the project until such time as the assets are substantially ready for their intended use.

Depletion and depreciation

Oil and gas assets are depleted, on a field-by-field basis, using the unit of production method based on entitlement to proven and probable reserves, taking account of estimated future development expenditure relating to those reserves. Changes in factors which affect unit of production calculations are dealt with prospectively. Depletion of oil and gas assets is taken through cost of sales.

Depreciation on other elements of property, plant and equipment is provided on a straight-line basis, and taken through general and administration expenses, at the following rates:

Office furniture and equipment	Five years
Fixtures and fittings	Ten years
Right-of-use assets*	Lease term

* Excludes Kraken FPSO which is depleted using the unit of production method in accordance with the related oil and gas assets

Each asset's estimated useful life, residual value and method of depreciation is reviewed and adjusted if appropriate at each financial year end. Any changes in estimate are accounted for on a prospective basis.

Impairment of tangible (excluding goodwill)

At each balance sheet date, discounted cash flow models comprising asset-by-asset life-of-field projections and risks specific to assets, using Level 3 inputs (based on IFRS 13 fair value hierarchy), have been used to determine the recoverable amounts for each CGU. The life of a field depends on the interaction of a number of variables; see note 2 for further details. Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis, including operating and capital expenditure, are derived from the Group's business plan. Oil price assumptions and discount rate assumptions used were as disclosed in note 2. If the recoverable amount of an asset (or CGU) is estimated to be less than its carrying amount, the carrying amount of the asset (or CGU) is reduced to its recoverable amount. An impairment loss is recognised immediately in the Group income statement.

Where an impairment loss subsequently reverses, the carrying amount of the asset (or CGU) is increased to the revised estimate of its recoverable amount, but only 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 CGU) in prior years. A reversal of an impairment loss is recognised immediately in the Group income statement.

	Oil and gas assets $'000	Office furniture, fixtures and fittings $'000	Right-of-use assets (note 23) $'000	Total $'000
Cost:				
At 1 January 2023	9,037,851	67,321	876,859	9,982,031
Additions	120,820	1,257	28,378	150,455
Change in decommissioning provision	53,333	–	–	53,333
Disposal	–	–	(243)	(243)
Reclassification from intangible assets (note 11)	31,803	–	–	31,803
At 1 January 2024	**9,243,807**	**68,578**	**904,994**	**10,217,379**
Additions	**325,813**	**394**	**16,453**	**342,660**
Change in decommissioning provision (note 22)	**(741)**	–	–	**(741)**
At 31 December 2024	**9,568,879**	**68,972**	**921,447**	**10,559,298**
Accumulated depreciation, depletion and impairment:				
At 1 January 2023	7,000,950	56,625	447,481	7,505,056
Charge for the year	239,640	2,689	55,979	298,308
Net impairment charge/(reversal) for the year	123,473	–	(6,077)	117,396
Disposal	–	–	(121)	(121)
At 1 January 2024	**7,364,063**	**59,314**	**497,262**	**7,920,639**
Charge for the year	**211,873**	**2,683**	**54,735**	**269,291**
Net impairment charge/(reversal) for the year	**75,428**	–	**(4,014)**	**71,414**
At 31 December 2024	**7,651,364**	**61,997**	**547,983**	**8,261,344**
Net carrying amount:				
At 31 December 2024	**1,917,515**	**6,975**	**373,464**	**2,297,954**
At 31 December 2023	1,879,744	9,264	407,732	2,296,740
At 1 January 2023	2,036,901	10,696	429,378	2,476,975

The amount of borrowing costs capitalised during the year ended 31 December 2024 was nil (2023: nil), reflecting the short-term nature of the Group's capital expenditure programmes.

Impairments
Impairments to the Group's producing assets and reversals of impairments are set out in the table below:

	Impairment (charge)/reversal		Recoverable amount[(i)]	
	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000	**31 December 2024 $'000**	31 December 2023 $'000
North Sea	**(71,414)**	(117,396)	**1,172,487**	1,323,009
Net pre-tax impairment (charge)/reversal	**(71,414)**	(117,396)		

(i) Recoverable amount has been determined on a fair value less costs of disposal basis (see note 2 for further details of judgements, estimates and assumptions made in relation to impairments). The amounts disclosed above are in respect of assets where an impairment (or reversal) has been recorded. Assets which did not have any impairment or reversal are excluded from the amounts disclosed

For information on judgements, estimates and assumptions made in relation to impairments, along with sensitivity analysis, see Use of judgements, estimates and assumptions: recoverability of asset carrying values within note 2.

The 2024 net impairment charge of $71.4 million relates to producing assets in the UK North Sea (charges of $2.0 million for GKA and Scolty/Crathes CGU, $62.5 million for Golden Eagle and $20.1 million for Alba offset by an impairment reversal of $13.2 million at Kraken). Impairment charges/reversals were primarily driven by EPL revisions, lower near-term oil price assumptions and changes in production profiles, partially offset by a lower discount rate.

The 2023 net impairment charge of $117.4 million related to producing assets in the UK North Sea (charges of $17.2 million for GKA and Scolty/Crathes CGU, $122.5 million for Golden Eagle and $9.1 million for Alba offset by an impairment reversal of $31.4 million at Kraken). Impairment charges/reversals were primarily driven by changes in production and cost profile updates, partially offset by higher forecast oil prices.

10. Goodwill
Accounting policy
Cost
Goodwill arising on a business combination is initially measured at cost, being the excess of the cost of the business combination over the net fair value of the identifiable assets, liabilities and contingent liabilities of the entity at the date of acquisition. If the fair value of the net assets acquired is in excess of the aggregate consideration transferred, the Group reassesses whether it has correctly identified all of the assets acquired and all of the liabilities assumed and reviews the procedures used to measure the amounts to be recognised at the acquisition date. If the reassessment still results in an excess of the fair value of net assets acquired over the aggregate consideration transferred, the gain is recognised in profit or loss.

Impairment of goodwill
Following initial recognition, goodwill is stated at cost less any accumulated impairment losses. In accordance with IAS 36 Impairment of Assets, goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the recoverable amount of the CGU (or group of CGUs) to which the goodwill relates should be assessed.

For the purposes of impairment testing, goodwill acquired is allocated to the CGU (or group of CGUs) that is expected to benefit from the synergies of the combination. Each unit or units to which goodwill is allocated represents the lowest level within the Group at which the goodwill is monitored for internal management purposes. Impairment is determined by assessing the recoverable amount of the CGU (or groups of CGUs) to which the goodwill relates. Where the recoverable amount of the CGU (or groups of CGUs) is less than the carrying amount of the CGU (or group of CGUs) containing goodwill, an impairment loss is recognised. Impairment losses relating to goodwill cannot be reversed in future periods. For information on significant estimates and judgements made in relation to impairments, see Use of judgements, estimates and assumptions: recoverability of asset carrying values within note 2.

A summary of goodwill is presented below:

	2024 $'000	2023 $'000
Cost and net carrying amount		
At 1 January	**134,400**	134,400
At 31 December	**134,400**	134,400

The majority of the goodwill, relates to the 75% acquisition of the Magnus oil field and associated interests. The remaining balance relates to the acquisition of the GKA and Scolty Crathes fields.

Impairment testing of goodwill
Goodwill, which has been acquired through business combinations, has been allocated to the UK North Sea segment grouping of CGUs, and this is therefore the lowest level at which goodwill is reviewed. The UK North Sea is a combination of oil and gas assets, as detailed within property, plant and equipment (note 9).

The recoverable amounts of the segment and fields have been determined on a fair value less costs of disposal basis. See notes 2 and 9 for further details. An impairment charge of nil was taken in 2024 (2023: nil) based on a fair value less costs to dispose valuation of the North Sea segment grouping of CGUs, as described above.

Sensitivity to changes in assumptions
The Group's recoverable value of assets is highly sensitive, *inter alia*, to oil price achieved and production volumes. A sensitivity has been run on the oil price assumptions, with a 10% change being considered to be a reasonable possible change for the purposes of sensitivity analysis (see note 2). A 10% reduction in oil price would result in an impairment charge of $66.7 million (2023: 10% reduction would not result in an impairment charge). A 17% reduction in oil price would fully impair goodwill (2023: 20%), however Management do not consider this to be a reasonable expectation.

11. Intangible assets
Accounting policy
Exploration and appraisal assets
Exploration and appraisal assets have indefinite useful lives and are accounted for using the successful efforts method of accounting. Pre-licence costs are expensed in the period in which they are incurred. Expenditure directly associated with exploration, evaluation or appraisal activities is initially capitalised as an intangible asset. Such costs include the costs of acquiring an interest, appraisal well drilling costs, payments to contractors and an appropriate share of directly attributable overheads incurred during the evaluation phase. For such appraisal activity, which may require drilling of further wells, costs continue to be carried as an asset, whilst related hydrocarbons are considered capable of commercial development. Such costs are subject to technical, commercial and management review to confirm the continued intent to develop, or otherwise extract value. When this is no longer the case, the costs are written off as exploration and evaluation expenses in the Group income statement. When exploration licences are relinquished without further development, any previous impairment loss is reversed and the carrying costs are written off through the Group income statement. When assets are declared part of a commercial development, related costs are transferred to property, plant and equipment. All intangible oil and gas assets are assessed for any impairment prior to transfer and any impairment loss is recognised in the Group income statement.

During the year ended 31 December 2024, there was no impairment of historical exploration and appraisal expenditures (2023: nil). During 2023, $31.8 million of intangible assets associated with the Kraken field were transferred to property, plant and equipment, reflecting updated drilling plans following assessment of previous seismic survey information. Also during 2023, Malaysia drilled an exploration well on the PM409 licence. The results indicated that there were no commercial prospects and as a result costs of $5.6 million were written off through the income statement during 2023 with an additional $0.2 million written off during 2024.

Other intangibles
UK emissions allowances ('UKAs') purchased to settle the Group's liability related to emissions are recognised on the balance sheet as an intangible asset at cost. The UKAs will be derecognised upon settling the liability with the respective regulator.

	Exploration and appraisal assets $'000	UK emissions allowances $'000	**Total $'000**
Cost:			
At 1 January 2023	154,937	1,199	156,136
Additions	10,467	876	11,343
Write-off of relinquished licences previously impaired	(485)	–	(485)
Write-off of unsuccessful exploration expenditure	(5,640)	–	(5,640)
Transfer to property, plant and equipment (note 9)	(31,803)	–	(31,803)
Disposal	–	(1,199)	(1,199)
At 1 January 2024	**127,476**	**876**	**128,352**
Additions	**3,686**	**1,138**	**4,824**
Write-off of unsuccessful exploration expenditure	**(183)**	–	**(183)**
Disposal	**(1,263)**	**(876)**	**(2,139)**
At 31 December 2024	**129,716**	**1,138**	**130,854**
Accumulated impairment:			
At 1 January 2023	(109,638)	–	(109,638)
Write-off of relinquished licences previously impaired	485	–	485
At 1 January 2024 and 31 December 2024	**(109,153)**	**–**	**(109,153)**
Net carrying amount:			
At 31 December 2024	**20,563**	**1,138**	**21,701**
At 31 December 2023	18,323	876	19,199
At 1 January 2023	45,299	1,199	46,498

12. Inventories

Accounting policy

Inventories of consumable well supplies and inventories of hydrocarbons are stated at the lower of cost and NRV, cost being determined on an average cost basis.

	2024 $'000	2023 $'000
Hydrocarbon inventories	**22,544**	21,189
Well supplies	**26,432**	63,608
	48,976	84,797

During 2024, a net gain of $6.9 million was recognised within cost of sales in the Group income statement relating to inventory (2023: net gain of $2.2 million). During the current year, following a review of the balance of well supplies held within inventory, it was concluded that some items met the definition of property, plant & equipment, and were reclassified during the current year end and presented as PP&E additions within PP&E (note 9).

The inventory valuation at 31 December 2024 is stated net of a provision of $28.5 million (2023: $36.3 million) to write-down well supplies to their estimated net realisable value.

13. Cash and cash equivalents

Accounting policy

Cash and cash equivalents includes cash at bank, cash in hand, cash deposited in relation to decommissioning security arrangements and highly liquid interest-bearing securities with original maturities of three months or fewer.

	2024 $'000	2023 $'000
Available cash	**226,317**	313,028
Restricted cash	**53,922**	544
Cash and cash equivalents	**280,239**	313,572

The carrying value of the Group's cash and cash equivalents is considered to be a reasonable approximation to their fair value due to their short-term maturities.

Restricted cash

During 2024, additional security was required to be provided in accordance with the Group's decommissioning security arrangements. EnQuest renewed its surety bond facilities and added three new providers, with $53.4 million of cash required to be placed on deposit (31 December 2023: nil). The remaining $0.5 million of restricted cash relates to bank guarantees for the Group's Malaysian assets (31 December 2023: $0.5 million).

14. Financial instruments and fair value measurement

Accounting policy

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument of another entity. Financial instruments are recognised when the Group becomes a party to the contractual provisions of the financial instrument.

Financial assets and financial liabilities are offset and the net amount is reported in the Group balance sheet if there is a currently enforceable legal right to offset the recognised amounts and there is an intention to settle on a net basis.

Financial assets

Financial assets are classified, at initial recognition, as amortised cost, fair value through other comprehensive income ('FVOCI'), or fair value through profit or loss ('FVPL'). The classification of financial assets at initial recognition depends on the financial assets' contractual cash flow characteristics and the Group's business model for managing them. The Group does not currently hold any financial assets at FVOCI, i.e. debt financial assets.

Financial assets are derecognised when the contractual rights to the cash flows from the financial asset expire, or when the financial asset and substantially all the risks and rewards are transferred.

Financial assets at amortised cost

Trade receivables, other receivables and joint operation receivables are measured initially at fair value and subsequently recorded at amortised cost, using the effective interest rate ('EIR') method, and are subject to impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired and EIR amortisation is included within finance costs.

The Group measures financial assets at amortised cost if both of the following conditions are met:

- The financial asset is held in a business model with the objective 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.

Prepayments, which are not financial assets, are measured at historical cost.

Impairment of financial assets

The Group recognises a loss allowance for expected credit loss ('ECL'), where material, for all financial assets held at the balance sheet date. ECLs are based on the difference between the contractual cash flows due to the Group, and the discounted actual cash flows that are expected to be received. Where there has been no significant increase in credit risk since initial recognition, the loss allowance is equal to 12-month expected credit losses. Where the increase in credit risk is considered significant, lifetime credit losses are provided. For trade receivables, a lifetime credit loss is recognised on initial recognition where material.

The provision rates are based on days past due for groupings of customer segments with similar loss patterns (i.e. by geographical region, product type, customer type and rating) and are based on historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment. The Group evaluates the concentration of risk with respect to trade receivables and contract assets as low, as its customers are joint venture partners and there are no indications of change in risk. Generally, trade receivables are written off when they become past due for more than one year and are not subject to enforcement activity.

Financial liabilities

Financial liabilities are classified, at initial recognition, as amortised cost or at FVPL.

Financial liabilities are derecognised when they are extinguished, discharged, cancelled or they expire. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as the derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the Group income statement.

Financial liabilities at amortised cost

Loans and borrowings, trade payables and other creditors are measured initially at fair value net of directly attributable transaction costs and subsequently recorded at amortised cost, using the EIR method. Loans and borrowings are interest bearing. Gains and losses are recognised in profit or loss when the liability is derecognised and EIR amortisation is included within finance costs.

Financial instruments at FVPL

The Group holds derivative financial instruments classified as held for trading, not designated as effective hedging instruments. The derivative financial instruments include forward currency contracts and commodity contracts, to address the respective risks; see note 27. The Group also enters into forward contracts for the purchase of UKAs to manage its exposure to carbon emission credit prices. Derivatives are carried as financial assets when the fair value is positive and as financial liabilities when the fair value is negative.

Financial instruments at FVPL are carried in the Group balance sheet at fair value, with net changes in fair value recognised in the Group income statement.

Financial assets with cash flows that are not solely payments of principal and interest are classified and measured at FVPL, irrespective of the business model. All financial assets not classified as measured at amortised cost or FVOCI as described above are measured at FVPL. Financial instruments with embedded derivatives are considered in their entirety when determining whether their cash flows are solely payment of principal and interest.

The Group also holds contingent consideration (see note 21) and a listed equity investment (see note 18). The movements of both are recognised within the Group income statement.

Fair value measurement

The following table provides the fair values and fair value measurement hierarchy of the Group's other financial assets and liabilities:

31 December 2024	Notes	Carrying Value $'000	Total $'000	Quoted prices in active markets (Level 1) $'000	Significant observable inputs (Level 2) $'000	Significant unobservable inputs (Level 3) $'000
Financial assets measured at fair value:						
Derivative financial assets measured at FVPL						
Gas commodity contracts	18(a)	**69**	**69**	**–**	**69**	**–**
Other financial assets measured at FVPL						**–**
Quoted equity shares		**6**	**6**	**6**	**–**	**–**
Total financial assets measured at fair value		**75**	**75**	**6**	**69**	**–**
Financial assets measured at amortised cost:						
Vendor financing facility	18(f)	**38,453**	**38,453**	**–**	**38,453**	**–**
Total financial assets measured at amortised cost(i)		**38,453**	**38,453**	–	38,453	**–**
Liabilities measured at fair value:						
Derivative financial liabilities measured at FVPL						
Commodity derivative contracts	18(a)	**10,497**	**10,497**	**–**	**10,497**	**–**
Forward foreign currency contracts	18(a)	**2,354**	**2,354**	**–**	**2,354**	**–**
Forward UKA contracts	18(a)	**8,729**	**8,729**	**–**	**8,729**	**–**
Other financial liabilities measured at FVPL						
Contingent consideration	21	**473,294**	**473,294**	**–**	**–**	**473,294**
Total liabilities measured at fair value		**494,874**	**494,874**	**–**	**21,580**	**473,294**
Liabilities measured at amortised cost						
Interest-bearing loans and borrowings(i)	17	**33,972**	**33,972**	–	**33,972**	–
Retail bond 9.00%(ii)	17	**169,371**	**161,461**	**161,461**	**–**	–
High yield bond 11.625%(ii)	17	**461,514**	**466,102**	**466,102**	**–**	–
Total liabilities measured at amortised cost(iii)		**664,857**	**661,535**	**627,563**	**33,972**	–

(i) Amortised cost is a reasonable approximation of the fair value

(ii) Carrying value includes accrued interest

(iii) Excludes related fees

31 December 2023	Notes	Carrying Value $'000	Total $'000	Quoted prices in active markets (Level 1) $'000	Significant observable inputs (Level 2) $'000	Significant unobservable inputs (Level 3) $'000
Financial assets measured at fair value:						
Derivative financial assets measured at FVPL						
Gas commodity contracts	18(a)	4,499	4,499	–	4,499	–
Other financial assets measured at FVPL						
Quoted equity shares		6	6	6	–	–
Total financial assets measured at fair value		4,505	4,505	6	4,499	–
Financial assets measured at amortised cost:						
Vendor financing facility	18(f)	145,103	145,103	–	145,103	–
Total financial assets measured at amortised cost(i)		145,103	145,103	–	145,103	–
Liabilities measured at fair value:						
Derivative financial liabilities measured at FVPL						
Oil commodity derivative contracts	18(a)	18,418	18,418	–	18,418	–
Forward UKA contracts	18(a)	8,261	8,261	–	8,261	–
Other financial liabilities measured at FVPL						
Contingent consideration	21	507,796	507,796	–	–	507,796
Total liabilities measured at fair value		534,475	534,475	–	26,679	507,796
Liabilities measured at amortised cost						
Interest-bearing loans and borrowings(i)	17	319,784	319,784	–	319,784	–
Retail bond 9.00%	17	169,669	158,683	158,683	–	–
High yield bond 11.625%	17	294,276	292,419	292,419	–	–
Total liabilities measured at amortised cost(ii)		783,729	770,886	451,102	319,784	–

(i) Amortised cost is a reasonable approximation of the fair value

(ii) Excludes related fees

Fair value hierarchy
All financial instruments for which fair value is recognised or disclosed are categorised within the fair value hierarchy, based on the lowest level input that is significant to the fair value measurement as a whole, as follows:

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

Level 2: Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly (i.e. prices) or indirectly (i.e. derived from prices) observable; and

Level 3: Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

Derivative financial instruments are valued by counterparties, with the valuations reviewed internally and corroborated with readily available market data (Level 2). Contingent consideration is measured at FVPL using the Level 3 valuation processes, details of which and a reconciliation of movements are disclosed in note 21. There have been no transfers between Level 1 and Level 2 during the period (2023: no transfers).

For the financial assets and liabilities measured at amortised cost but for which fair value disclosures are required, the fair value of the bonds classified as Level 1 was derived from quoted prices for that financial instrument, while interest-bearing loans and borrowings and the vendor financing facility were calculated at amortised cost using the effective interest method to capture the present value (Level 3). A reconciliation of movements is disclosed in note 29.

15. Trade and other receivables

	2024 $'000	2023 $'000
Current		
Trade receivables	**20,151**	31,905
Joint venture receivables	**106,963**	79,036
Under-lift position	**16,806**	22,309
VAT receivable	**7,574**	3,314
Other receivables	**4,729**	3,715
Prepayments	**7,822**	2,781
Accrued income	**66,926**	82,426
Total current	**230,971**	225,486
Non-current		
Other receivables	**2,102**	–
Total non-current	**2,102**	–

The carrying values of the Group's trade, joint venture and other receivables as stated above are considered to be a reasonable approximation to their fair value largely due to their short-term maturities. Under-lift is valued at the lower of cost or NRV at the prevailing balance sheet date (note 4(b)).

Trade receivables are non-interest-bearing and are generally on 15 to 30-day terms. Joint venture receivables relate to amounts billable to, or recoverable from, joint venture partners. Receivables are reported net of any ECL with no losses recognised as at 31 December 2024 or 2023.

Non-current trade and other receivables represents capitalised fees associated with the Group's Reserve Based Lending Facility that were reclassed to trade and other receivables to better reflect the variable nature of the facility following the repayment in full of the outstanding principal ($140.0 million) in February 2024.

16. Trade and other payables

	2024 $'000	2023 $'000
Current		
Trade payables	**138,822**	75,981
Accrued expenses	**209,225**	228,664
Over-lift position	**16,849**	18,824
Joint venture creditors	**46,187**	20,262
Other payables	**3,307**	3,678
Total Current	**414,390**	347,409
Non-current		
Joint venture creditors	–	32,917
Total Non-current	–	32,917

The carrying value of the Group's current trade and other payables as stated above is considered to be a reasonable approximation to their fair value largely due to the short-term maturities. Certain trade and other payables will be settled in currencies other than the reporting currency of the Group, mainly in Sterling. Trade payables are normally non-interest-bearing and settled on terms of between 10 and 30 days.

Accrued expenses include accruals for capital and operating expenditure in relation to the oil and gas assets and interest accruals.

The carrying value of the Group's 2023 non-current trade and other payables as stated above was considered to be a reasonable approximation to their fair value as this represented a specific bi-lateral agreement between counterparties with the liability extinguished in full over time in accordance with the agreed schedule. The outstanding amount at 31 December 2024 is now presented within current trade and other payables.

17. Loans and borrowings

	2024 $'000	2023 $'000
Loans	**33,972**	311,231
Bonds	**630,885**	463,945
	664,857	775,176

The Group's borrowings are carried at amortised cost as follows:

	2024			2023		
	Principal $'000	**Fees $'000**	**Total $'000**	Principal $'000	Fees $'000	Total $'000
RBL facility[(i)]	–	–	–	140,000	(4,920)	135,080
Term loan facility	–	–	–	150,000	(3,633)	146,367
SVT working capital facility	**33,972**	–	**33,972**	29,784	–	29,784
High yield bond 11.625%	**465,000**	**(10,661)**	**454,339**	305,000	(10,724)	294,276
Retail bond 9.00%	**167,101**	–	**167,101**	169,669	–	169,669
Accrued interest[(ii)]	**9,445**	–	**9,445**	–	–	–
Total borrowings	**675,518**	**(10,661)**	**664,857**	794,453	(19,277)	775,176
Due within one year			**43,417**			27,364
Due after more than one year			**621,440**			747,812
Total borrowings			**664,857**			775,176

(i) Capitalised fees were reclassed in the current period to trade and other receivables to better reflect the variable nature of the facility
(ii) Accrued interest on borrowings has been reclassed in the current period to better reflect the total borrowings balance (comparative information has not been restated as it is not material). Accrued interest includes bond interest accruals of $9.4 million

See liquidity risk – note 27 for the timing of cash outflows relating to loans and borrowings.

Reserve Based Lending facility ('RBL')
In October 2022, the Group agreed an amended and restated RBL facility with commitments of $500.0 million, reducing in accordance with an amortisation schedule, a sub limit for drawings in the form of Letters of Credit of $75.0 million and a standard accordion facility which allowed the Group to increase commitments by an amount of up to $300.0 million on no more than three occasions. The maturity of the facility is April 2027. Funds can only be drawn under the RBL to a maximum amount of the lesser of (i) the total commitments and (ii) the borrowing base amount. Interest accrues at 4.00% until July 2025 when it increases to 4.50%, plus a combination of an agreed credit adjustment spread and the Secured Overnight Financing Rate ('SOFR'). The Group fully repaid the $140.0 million of its drawn Reserve Based Lending Facility in February 2024. At 31 December 2024, $176.4 million remained available for drawdown under the RBL (2023: $166.2 million). Effective from 1 January 2025, the amount available to drawdown increased to $237.1 million as a result of the annual redetermination process.

At 31 December 2024, the Letter of Credit utilisation was $54.1 million (2023: $43.5 million).

Term loan facility
In August 2023, the Group agreed a second lien US Dollar term loan facility of $150.0 million which was drawn down in full in September 2023 and incurred interest at SOFR +7.90%. In October 2024, the term loan, plus the early redemption fee of $4.7 million, was fully repaid utilising the proceeds from the high yield bond tap. The early redemption fee and the remaining unamortised costs of $2.9 million were expensed within finance costs.

SVT working capital facility
EnQuest has extended the £42.0 million revolving loan facility with a joint operations partner to fund the short-term working capital cash requirements of SVT and associated interests until April 2027. The facility is guaranteed by BP EOC Limited (joint operations partner) until the earlier of: a) the date on which production from Magnus permanently ceases; or b) if the operating agreements for both SVT and associated infrastructure are amended to allow for cash calling. The facility is able to be drawn down against, in instalments, and accrues interest at 2.05% per annum plus GBP Sterling Over Night Index Average ('SONIA').

Vendor Loan facility
In August 2024, the Group entered into a deferred payment facility agreement with a third-party vendor providing capacity for refinancing the payment of existing invoices up to an amount of £23.7 million, with interest payable monthly at a rate of 9.50% per annum. At 31 December 2024, nil was drawn down on the facility, with $20.7 million drawn by the end of February 2025.

High yield bond 11.625%
In October 2022, the Group concluded an offer of $305.0 million for a US Dollar high yield bond. In October 2024, the Group concluded a tap of an additional $160.0 million of the US Dollar high yield bond on the same terms and conditions as the existing bond. The notes accrue a fixed coupon of 11.625% payable semi-annually in arrears with a maturity date of November 2027. Associated fees of $3.4 million were capitalised and are being amortised over the period of the bond.

The above carrying value of the bond as at 31 December 2024 is $454.3 million (2023: $294.3 million). This includes bond principal of

$465.0 million (2023: $305.0 million) and unamortised issue premium on the tap of $1.4 million less the unamortised original issue discount of $2.4 million (2023: $3.3 million) and unamortised fees of $9.7 million (2023: $7.4 million). The fair value of the high yield bond is disclosed in note 14.

Retail bond 9.00%
On 27 April 2022, the Group issued a new 9.00% retail bond following a successful partial exchange and cash offer. The principal of the retail bond 9.00% raised by the partial exchange and cash offer totalled £133.3 million. The notes accrue a fixed coupon of 9.00% payable semi-annually in arrears and are due to mature in October 2027.

The above carrying value of the bond as at 31 December 2024 is $167.1 million (2023: $169.7 million). All fees associated with this offer were recognised in the income statement in 2022. The fair value of the retail bond 9.00% is disclosed in note 14.

18. Other financial assets and financial liabilities

(a) Summary as at year end

	2024		2023	
	Assets $'000	**Liabilities $'000**	Assets $'000	Liabilities $'000
Fair value through profit or loss:				
Derivative commodity contracts	**69**	**10,497**	4,499	18,418
Forward foreign currency contracts	**–**	**2,354**	–	–
Derivative UKA contracts	**–**	**8,729**	–	8,261
Amortised cost:				
Other receivables (Vendor financing facility) (notes 18(f), 24)	**–**	**–**	108,827	–
Total current	**69**	**21,580**	113,326	26,679
Fair value through profit or loss:				
Quoted equity shares	**6**	**–**	6	–
Amortised cost:				
Other receivables (Vendor financing facility) (notes 18(f), 24)	**38,453**	**–**	36,276	–
Total non-current	**38,459**	**–**	36,282	–
Total other financial assets and liabilities	**38,528**	**21,580**	149,608	26,679

(b) Income statement impact
The income/(expense) recognised for derivatives are as follows:

	Revenue and other operating income		**Cost of sales**	
Year ended 31 December 2024	**Realised $'000**	**Unrealised $'000**	**Realised $'000**	**Unrealised $'000**
Commodity options	**(19,899)**	**10,617**	**–**	**–**
Commodity swaps	**7,467**	**(7,340)**	–	**–**
Commodity futures	**(475)**	**(187)**	–	**–**
Foreign exchange contracts	**–**	**–**	**2,859**	**(2,354)**
UKA contracts	–	**–**	**(7,594)**	**(469)**
	(12,907)	**3,090**	**(4,735)**	**(2,823)**

	Revenue and other operating income		Cost of sales	
Year ended 31 December 2023	Realised $'000	Unrealised $'000	Realised $'000	Unrealised $'000
Commodity options	(21,463)	19,148	–	–
Commodity swaps	12,474	9,315	–	–
Commodity futures	(2,275)	–	–	–
Foreign exchange contracts	–	–	5,695	–
UKA contracts	–	–	(2,856)	(3,832)
	(11,264)	28,463	2,839	(3,832)

(c) Commodity contracts
The Group uses derivative financial instruments to manage its exposure to the oil price, including put and call options, swap contracts and futures.

For the year ended 31 December 2024, losses totalling $9.8 million (2023: gains of $17.2 million) were recognised in respect of commodity contracts measured as FVPL. This included losses totalling $12.9 million (2023: losses of $11.3 million) realised on contracts that matured during the year, and mark-to-market unrealised gains totalling $3.1 million (2023: gains of $28.5 million).

The mark-to-market value of the Group's open commodity contracts as at 31 December 2024 was a net liability of $10.4 million (2023: net liability of $13.9 million).

(d) Foreign currency contracts

The Group enters into a variety of foreign currency contracts, primarily in relation to Sterling. During the year ended 31 December 2024, gains totalling $0.5 million (2023: gains of $5.7 million) were recognised in the Group income statement. This included realised gains totalling $2.9 million (2023: gains of $5.7 million) on contracts that matured in the year.

The mark-to-market value of the Group's open contracts as at 31 December 2024 was a net liability of $2.4 million (2023: nil).

(e) UK emissions allowance forward contracts

The Group enters into forward contracts for the purchase of UKAs to manage its exposure to carbon emission credit prices. During the year ended 31 December 2024, losses totalling $8.1 million (2023: losses of $6.7 million) were recognised in the Group income statement. This included realised losses totalling $7.6 million (2023: losses of $2.9 million) on contracts that matured in the year.

The mark-to-market value of the Group's open contracts as at 31 December 2024 was a net liability of $8.7 million (2023: $8.3 million).

(f) Other receivables

	Other receivables $'000	Equity shares $'000	Total $'000
At 1 January 2023	**–**	**6**	**6**
Additions[(i)]	**145,103**	**–**	**145,103**
At 31 December 2023	**145,103**	**6**	**145,109**
Interest	**3,263**	**–**	**3,263**
Repayments	**(107,518)**	**–**	**(107,518)**
Foreign Exchange	**(2,395)**	**–**	**(2,395)**
At 31 December 2024	**38,453**	**6**	**38,459**
Current			**–**
Non-current			**38,459**
			38,459

[(i)]Additions in 2023 relate to a vendor financing facility entered into with RockRose Energy Limited on 29 December 2023 following the farm-down of a 15.0% share in the EnQuest Producer FPSO and capital items associated with the Bressay development. $107.5 million was repaid in the first quarter of 2024 with the remainder repayable through future net cash flows from the Bressay field. Interest on the outstanding amount accrues at 2.5% plus the Bank of England's Base Rate.

19. Share capital and reserves

Accounting policy

Share capital and share premium

The balance classified as equity share capital includes the total net proceeds (both nominal value and share premium) on issue of registered share capital of the parent company. Share issue costs associated with the issuance of new equity are treated as a direct reduction of proceeds. The share capital comprises only one class of Ordinary share. Each Ordinary share carries an equal voting right and right to a dividend.

Treasury shares

Represents amounts transferred following purchase of the Company's own shares out of distributable profits, with those shares available for resale into the market, transfer to the Group's Employee Benefit Trust ('EBT') where they can be used to satisfy awards made under the Company's share-based incentive schemes, or cancelled.

Capital redemption reserve

Represents the par value of shares cancelled following the purchase of the Company's own shares out of distributable profits.

Retained earnings

Retained earnings contain the accumulated profits/(losses) of the Group.

Share-based payments reserve

Equity-settled share-based payment transactions are measured at the fair value of the services received, and the corresponding increase in equity is recorded. EnQuest PLC shares held by the Group in the EBT are recognised at cost and are deducted from the share-based payments reserve, as they are held to satisfy awards made under equity-settled share-based payment transactions. Consideration received for the sale of such shares is also recognised in equity, with any difference between the proceeds from the sale and the original cost being taken to reserves. No gain or loss is recognised in the Group income statement on the purchase, sale, issue or cancellation of equity shares.

Authorised, issued and fully paid	Ordinary shares of £0.05 each Number	Share capital $'000	Share premium $'000	Treasury shares $'000	Capital redemption reserve $'000	Total $'000
At 1 January 2024	**1,912,304,113**	**133,285**	**260,546**	**–**	**–**	**393,831**
Issue of new shares to EBT	**3,620,226**	**229**	**–**	**–**	**–**	**229**
Repurchase and cancellation of shares	**(30,894,836)**	**(2,006)**	**–**	**(4,425)**	**2,006**	**(4,425)**
At 31 December 2024	**1,885,029,503**	**131,508**	**260,546**	**(4,425)**	**2,006**	**389,635**

During 2024, a share buyback programme was executed with a total of 55,894,836 Ordinary shares repurchased as at 31 December 2024. The first 25,000,000 Ordinary shares purchased under the Programme are held in Treasury for issue in due course to the Company's EBT to satisfy the anticipated future exercise of options and awards made to employees and Executive Directors of EnQuest PLC pursuant to certain of the Company's existing share plans. The remaining 30,894,836 Ordinary shares were cancelled.

At 31 December 2024, there were 972,269 shares held by the EBT (2023: 8,449,793) which are included within the share-based payment reserve. The movement in the year was 11,097,750 shares used to satisfy awards made under the Company's share-based incentive schemes offset by a subscription for 3,620,226 additional Ordinary shares.

At 1 January 2023, the number of Ordinary shares was 1,885,924,339. In December 2023, 26,379,774 shares were issued and subsequently transferred to the EBT.

20. Share-based payment plans

Accounting policy

Eligible employees (including Executive Directors) of the Group receive remuneration in the form of share-based payment transactions, whereby employees render services in exchange for shares or rights over shares of EnQuest PLC.

The cost of these equity-settled transactions is measured by reference to the fair value at the date on which they are granted. The fair value of awards is calculated in reference to the scheme rules at the market value, being the average middle market quotation of a share for the three immediately preceding dealing days as derived from the Daily Official List of the London Stock Exchange, provided such dealing days do not fall within any period when dealings in shares are prohibited because of any dealing restriction.

The cost of equity-settled transactions is recognised over the vesting period in which the relevant employees become fully entitled to the award. The cumulative expense recognised for equity-settled transactions at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the Group's best estimate of the number of equity instruments that will ultimately vest. The Group income statement charge or credit for a period represents the movement in cumulative expense recognised as at the beginning and end of that period.

In valuing the transactions, no account is taken of any service or performance conditions, other than conditions linked to the price of the shares of EnQuest PLC (market conditions) or 'non-vesting' conditions, if applicable. No expense is recognised for awards that do not ultimately vest, except for awards where vesting is conditional upon a market or non-vesting condition, which are treated as vesting irrespective of whether or not the market or non-vesting condition is satisfied, provided that all other performance conditions are satisfied. Equity awards cancelled are treated as vesting immediately on the date of cancellation, and any expense not previously recognised for the award at that date is recognised in the Group income statement.

The Group operates a number of equity-settled employee share plans under which share units are granted to the Group's senior leaders and certain other employees. These plans typically have a three-year performance or restricted period. Leaving employment will normally preclude the conversion of units into shares, but special arrangements apply for participants that leave for qualifying reasons.

The share-based payment expense recognised for each scheme was as follows:

	2024 $'000	2023 $'000
Performance Share Plan	**511**	2,120
Other performance share plans	**64**	231
Sharesave Plan	**408**	969
	983	3,320

The following table shows the number of shares potentially issuable under the Group's various equity-settled employee share plans, including the number of options outstanding and the number of options exercisable at the end of each year.

Share plans	**2024 Number**	2023 Number
Outstanding at 1 January	**87,367,455**	102,271,264
Granted during the year	**35,353,664**	33,940,859
Exercised during the year	**(7,291,023)**	(19,459,260)
Forfeited during the year	**(26,812,413)**	(29,385,408)
Outstanding at 31 December	**88,617,683**	87,367,455
Exercisable at 31 December	**9,138,271**	17,944,371

Within the Group's equity-settled employee share plans detailed above, the Group operates an approved savings-related share option scheme (the 'Sharesave Plan'). The plan is based on eligible employees being granted options and their agreement to opening a Sharesave account with a nominated savings carrier and to save over a specified period, either three or five years. The right to exercise the option is at the employee's discretion at the end of the period previously chosen, for a period of six months.

The following table shows the number of shares potentially issuable under equity-settled employee share option plans, including the number of options outstanding, the number of options exercisable at the end of each year and the corresponding weighted average exercise prices.

Sharesave options	**2024** Number	**2024** Weighted average exercise price $	2023 Number	2023 Weighted average exercise price $
Outstanding at 1 January	**18,658,144**	**0.16**	33,308,249	0.14
Granted during the year	**–**	**–**	10,268,853	0.14
Exercised during the year	**(5,478,693)**	**0.13**	(19,977,354)	0.13
Forfeited during the year	**(3,223,434)**	**0.15**	(4,941,604)	0.17
Outstanding at 31 December	**9,956,017**	**0.15**	18,658,144	0.16
Exercisable at 31 December	**323,886**	**0.24**	6,553,159	0.13

21. Contingent consideration

Accounting policy

When the consideration transferred by the Group in a business combination includes a contingent consideration arrangement, the contingent consideration is measured at its acquisition-date fair value and included as part of the consideration transferred in a business combination. Changes in fair value of the contingent consideration that qualify as measurement period adjustments are adjusted retrospectively, with corresponding adjustments against goodwill. 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 depicted below is remeasured to fair value at subsequent reporting dates with changes in fair value recognised in profit or loss. Contingent consideration that is classified as equity if any, is not remeasured at subsequent reporting dates and its subsequent settlement is accounted for within equity.

Contingent consideration is discounted at a risk-free rate combined with a risk premium, calculated in alignment with IFRS 13 and the unwinding of the discount is presented as part of the overall fair value change within other (expenses)/income.

Any contingent consideration included in the consideration payable for an asset acquisition is recorded at fair value at the date of acquisition and included in the initial measurement of cost.

Settlement of contingent consideration recorded at fair value through profit or loss is recorded as investing outflows in the cash flow statement to the extent cumulative amounts paid do not exceed the amount recognised at the date of acquisition, with any excess recorded as an operating cash outflow. Settlement of contingent consideration relating to an asset acquisition is recorded as an investing cash outflow.

	Magnus 75% $'000	**Magnus decommissioning-linked liability $'000**	**Total $'000**
At 31 December 2023	**488,007**	**19,789**	**507,796**
Unwinding of discount (see note 4(d))	**55,144**	**2,301**	**57,445**
Other changes in fair value (see note 4(d))	**(43,353)**	**1,812**	**(41,541)**
Utilisation	**(48,465)**	**(1,941)**	**(50,406)**
At 31 December 2024	**451,333**	**21,961**	**473,294**
Classified as:			
Current	**18,905**	**1,498**	**20,403**
Non-current	**432,428**	**20,463**	**452,891**
	451,333	**21,961**	**473,294**

75% Magnus acquisition contingent consideration

On 1 December 2018, EnQuest completed the acquisition of the additional 75% interest in the Magnus oil field ('Magnus') and associated interests (collectively the 'Transaction assets') which was part funded through a profit share arrangement with bp whereby EnQuest and bp share the net cash flow generated by the 75% interest on a 50:50 basis, subject to a cap of $1.0 billion received by bp. This contingent consideration is a financial liability classified as measured at FVPL. The fair value of contingent consideration has been determined by calculating the present value of the future expected cash flows expected to be paid and is considered a Level 3 valuation under the fair value hierarchy. Future cash flows are estimated based on inputs including future oil prices, production volumes and operating costs. Oil price assumptions and discount rate assumptions used were as disclosed in Use of judgements, estimates and assumptions within note 2. The contingent consideration was fair valued at 31 December 2024, which resulted in a decrease in fair value (excluding the impact of unwind of discount) of $43.4 million (2023: decrease of $69.8 million). Thi decrease in 2024 reflects a reduction in the Group's near-term oil price assumptions and changes in the assets cost and production profile. The decrease in 2023 reflected a 1.3% increase in the discount rate to 11.3% (2022: 10.0%) and changes in the asset cost profile, partially offset by the Group's increased oil price assumptions. The overall fair value accounting effect including the unwinding of discount, totalling a charge of $11.8million (2023: credit of $13.2 million) on the contingent consideration were recognised in the Group income statement. At 31 December 2024, the contingent profit-sharing arrangement cap of $1.0 billion was forecast to be met in the present value calculations (31 December 2023: cap was forecast to be met). Within the statement of cash flows, the profit share element of the repayment, $48.5 million (2023: $65.5 million), is disclosed separately under investing activities. At 31 December 2024, the contingent consideration for Magnus was $451.3 million (31 December 2023: $488.0 million).

Management has considered alternative scenarios to assess the valuation of the contingent consideration including, but not limited to, the key accounting estimates relating to the oil price, discount rate and their interrelationship with production and the profit-share arrangement.

As described within note 2, oil price has been assessed by Management as the only key source of estimation uncertainty due to its material impact on revenue, which in turn results in changes in the contingent consideration present value calculations due to the timing of future cashflows and production profiles. As the profit-sharing cap of $1.0 billion is forecast to be met in the present value calculations, sensitivity analysis has only been undertaken on a reduction in the oil price assumptions of 10%, which is considered to be a reasonably possible change. This results in a reduction of $51.1 million to the contingent consideration (2023: reduction of $83.3 million). A 1.0% reduction in the discount rate applied, which is considered a reasonably possible change given the prevailing macroeconomic conditions, would increase reported contingent consideration by $19.8 million. A 1.0% increase would decrease reported contingent consideration by $18.6 million.

The payment of contingent consideration is limited to cash flows generated from Magnus. Therefore, no contingent consideration is payable if insufficient cash flows are generated over and above the requirements to operate the asset. By reference to the conditions existing at 31 December 2024, the maturity analysis of the contingent consideration is disclosed in Risk management and financial instruments: liquidity risk (note 27).

Magnus decommissioning-linked contingent consideration
As part of the Magnus and associated interests acquisition, bp retained the decommissioning liability in respect of the existing wells and infrastructure and EnQuest agreed to pay additional consideration in relation to the management of the physical decommissioning costs of Magnus. At 31 December 2024, the amount due to bp calculated on an after-tax basis by reference to 30% of bp's decommissioning costs on Magnus was $22.0 million (2023: $19.8 million). Any reasonably possible change in assumptions would not have a material impact on the provision.

Golden Eagle contingent consideration
Part of the Golden Eagle acquisition consideration included an amount that was contingent on the average oil price between July 2021 and June 2023. Over the period July 2021 to June 2023, the average oil price was $89.6/bbl. As such, at 30 June 2023, the contingent consideration was valued at $50.0 million with settlement of this liability completing in July 2023. The balance at 31 December 2024 was nil (31 December 2023: nil).

22. Provisions

Accounting policy

Decommissioning

Provision for future decommissioning costs is made in full when the Group has an obligation: to dismantle and remove a facility or an item of plant; to restore the site on which it is located; and when a reasonable estimate of that liability can be made. The Group's provision primarily relates to the future decommissioning of production facilities and pipelines.

A decommissioning asset and liability are recognised, within property, plant and equipment and provisions, respectively, at the present value of the estimated future decommissioning costs. The decommissioning asset is amortised over the life of the underlying asset on a unit of production basis over proven and probable reserves, included within depletion in the Group income statement. Any change in the present value of estimated future decommissioning costs is reflected as an adjustment to the provision and the oil and gas asset for producing assets. For assets that have ceased production, the change in estimate is reflected as an adjustment to the provision and the Group income statement, via other income or expense. The unwinding of the decommissioning liability is included under finance costs in the Group income statement.

These provisions have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required, which will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning liabilities is likely to depend on the dates when the fields cease to be economically viable. This in turn depends on future oil prices, which are inherently uncertain. See Use of judgements, estimates and assumptions: provisions within note 2.

Other

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

	Decommissioning provision $'000	Thistle decommissioning provision $'000	Other provisions $'000	Total $'000
At 31 December 2023	**755,762**	**25,355**	**14,180**	**795,297**
Additions during the year[(i)]	**2,893**	**–**	**835**	**3,728**
Changes in estimates[(i)]	**3,032**	**412**	**–**	**3,444**
Unwinding of discount	**30,290**	**911**	**–**	**31,201**
Utilisation	**(50,412)**	**(8,319)**	**(9,063)**	**(67,794)**
Foreign exchange	**–**	**(11)**	**241**	**230**
At 31 December 2024	**741,565**	**18,348**	**6,193**	**766,106**
Classified as:				
Current	**42,030**	**7,700**	**5,400**	**55,130**
Non-current	**699,535**	**10,648**	**793**	**710,976**
	741,565	**18,348**	**6,193**	**766,106**

(i) Includes $6.7 million relating to assets in decommissioning disclosed in note 4(d) and $(0.7) million related to producing assets disclosed in note 9

Decommissioning provision
The Group's total provision represents the present value of decommissioning costs which are expected to be incurred up to 2050, assuming no further development of the Group's assets. Additions during the year primarily relate to the decommissioning provision recognised due to drilling of new wells in Golden Eagle. Changes in estimates during the year primarily reflect the net effect of $78.0 million increase in the underlying cost

estimates partly offset by $59.0 million impact from the increase in the discount rate and $12.4 million foreign exchange impact due to the weakening of Sterling to US Dollar exchange rates. At 31 December 2024, an estimated $281.1 million is expected to be utilised between one and five years (2023: $175.7 million), $280.0 million within six to ten years (2023: $355.6 million), and the remainder in later periods. For sensitivity analysis see Use of judgements, estimates and assumptions within note 2.

The Group enters into surety bonds principally to provide security for its decommissioning obligations (see note 13). The surety bond facilities, which expired in December 2023, were renewed for 12 months, subject to ongoing compliance with the terms of the Group's borrowings. At 31 December 2024, the Group held surety bonds totalling $277.0 million (2023: $250.4 million).

Thistle decommissioning provision
In 2018, EnQuest exercised the option to receive $50.0 million from bp in exchange for undertaking the management of the physical decommissioning activities for Thistle and Deveron and making payments by reference to 7.5% of bp's share of decommissioning costs of the Thistle and Deveron fields, with the liability recognised within provisions. At 31 December 2024, the amount due to bp by reference to 7.5% of bp's decommissioning costs on Thistle and Deveron was $18.3 million (2023: $25.4 million), with the reduction mainly reflecting the utilisation in the period. Change in estimates of $0.4 million are included within other expense (2023: $1.6 million) and unwinding of discount of $0.9 million is included within finance costs (2023: $1.1 million).

Other provisions
At 31 December 2023, the provision included a dispute with a third-party contractor of $9.1 million including legal costs and interest charges. In August 2024, the Malaysian Court of Appeal issued a judgement that funds held in escrow, should be released to the third party supplier pending resolution of the final arbitration decision. As such $8.6 million was released from escrow and hence deducted from the provision. Should the final arbitration decision find in the favour of EnQuest, EnQuest would seek reimbursement of any funds transferred. The Group expects the dispute to be settled in 2025.

23. Leases

Accounting policy
As a lessee
The Group recognises a right-of-use asset and a lease liability at the lease commencement date.

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, or, if that rate cannot be readily determined, the Group uses its incremental borrowing rate.

The incremental borrowing rate is the rate that the Group would have to pay for a loan of a similar term, and with similar security, to obtain an asset of similar value. The incremental borrowing rate is determined based on a series of inputs including: the term, the risk-free rate based on government bond rates and a credit risk adjustment based on EnQuest bond yields.

Lease payments included in the measurement of the lease liability comprise:
- fixed lease payments (including in-substance fixed payments), less any lease incentives;
- variable lease payments that depend on an index or rate, initially measured using the index or rate at the commencement date;
- the exercise price of purchase options, if the lessee is reasonably certain to exercise the options; and
- payments of penalties for terminating the lease, if the lease term reflects the exercise of an option to terminate the lease.

The lease liability is subsequently recorded at amortised cost, using the effective interest rate method. The liability is remeasured when there is a change in future lease payments arising from a change in an index or rate or if the Group changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero. The Group did not make any such adjustments during the periods presented.

The right-of-use asset is measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. Right-of-use assets are depreciated over the shorter period of lease term and 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.

The Group applies the short-term lease recognition exemption to those leases that have a lease term of 12 months or less from the commencement date. It also applies the low-value assets recognition exemption to leases of assets below £5,000. Lease payments on short-term leases and leases of low-value assets are recognised as an expense on a straight-line basis over the lease term.

The Group applies IAS 36 Impairment of Assets to determine whether a right-of-use asset is impaired and accounts for any identified impairment loss as described in the 'property, plant and equipment' policy (see note 9).

Variable rents that do not depend on an index or rate are not included in the measurement of the lease liability and the right-of-use asset. The related payments are recognised as an expense in the period in which the event or condition that triggers those payments occurs and are included within 'cost of sales' or 'general and administration expenses' in the Group income statement.

For leases within joint ventures, the Group assesses on a lease-by-lease basis the facts and circumstances. This relates mainly to leases of vessels. Where all parties to a joint operation jointly have the right to control the use of the identified asset and all parties have a legal obligation to make lease payments to the lessor, the Group's share of the right-of-use asset and its share of the lease liability will be recognised on the Group balance sheet. This may arise in cases where the lease is signed by all parties to the joint operation or the joint operation partners are named within the lease. However, in cases where EnQuest is the only party with the legal obligation to make lease payments to the lessor, the full lease liability and right-of-use asset will be recognised on the Group balance sheet. This may be the case if, for example, EnQuest, as operator of the joint operation, is the sole signatory to the lease. If the underlying asset is used for the performance of the joint operation agreement, EnQuest will recharge the associated costs in line with the joint operating agreement.

As a lessor
When the Group acts as a lessor, it determines at lease inception whether each lease is a finance lease or an operating lease. Whenever the

terms of the lease transfer substantially all the risks and rewards of ownership to the lessee, the contract is classified as a finance lease. All other leases are classified as operating leases.

When the Group is an intermediate lessor, it accounts for the head-lease and the sub-lease as two separate contracts. The sub-lease is classified as a finance or operating lease by reference to the right-of-use asset arising from the head-lease.

Rental income from operating leases is recognised on a straight-line basis over the term of the relevant lease. Initial direct costs incurred in negotiating and arranging an operating lease are added to the carrying amount of the leased asset and recognised on a straight-line basis over the lease term.

Amounts due from lessees under finance leases are recognised as receivables at the amount of the Group's net investment in the leases. Finance lease income is allocated to reporting periods so as to reflect a constant periodic rate of return on the Group's net investment outstanding in respect of the leases.

When a contract includes lease and non-lease components, the Group applies IFRS 15 to allocate the consideration under the contract to each component.

Right-of-use assets and lease liabilities

Set out below are the carrying amounts of the Group's right-of-use assets and lease liabilities and the movements during the period:

	Right-of-use assets $'000	**Lease liabilities $'000**
As at 31 December 2022	429,378	482,066
Additions in the period	28,378	28,378
Depreciation expense	(55,979)	–
Impairment reversal	6,077	–
Disposal	(122)	–
Interest expense	–	43,801
Payments	–	(135,675)
Foreign exchange movements	–	3,604
As at 31 December 2023	**407,732**	**422,174**
Additions in the period (see note 9)	**16,453**	**16,453**
Depreciation expense (see note 9)	**(54,735)**	**–**
Impairment reversal (see note 9)	**4,014**	**–**
Interest expense	**–**	**27,673**
Payments	**–**	**(130,065)**
Foreign exchange movements	**–**	**(979)**
As at 31 December 2024	**373,464**	**335,256**
Current		**46,994**
Non-current		**288,262**
		335,256

The carrying value of the right-of-use assets include $340.9 million (2023: $372.6 million) of oil and gas assets and $32.6 million (2023: $35.1 million) of buildings.
The Group leases assets, including the Kraken FPSO, property, and oil and gas vessels, with a weighted average lease term of four years. The maturity analysis of lease liabilities is disclosed in note 27.

Amounts recognised in profit or loss

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Depreciation expense of right-of-use assets	**54,735**	55,979
Impairment of right-of-use assets	**(4,014)**	(6,077)
Interest expense on lease liabilities	**27,673**	43,801
Rent expense – short-term leases	**13,860**	5,153
Rent expense – leases of low-value assets	**33**	113
Total amounts recognised in profit or loss	**92,287**	98,969

Amounts recognised in statement of cash flows

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Total cash outflow for leases	**130,065**	135,675

Leases as lessor
The Group sub-leases part of Annan House, the Aberdeen office. The sub-lease is classified as an operating lease, as all the risks and rewards incidental to the ownership of the right-of-use asset are not all substantially transferred to the lessee. Rental income recognised by the Group during 2024 was $2.2 million (2023: $2.3 million).

The following table sets out a maturity analysis of lease payments, showing the undiscounted lease payments to be received after the reporting date:

	2024 $'000	2023 $'000
Less than one year	**2,029**	2,682
One to two years	**858**	2,011
Two to three years	**860**	872
Three to four years	**875**	873
Four to five years	**882**	889
More than five years	**1,856**	2,790
Total undiscounted lease payments	**7,360**	10,117

24. Deferred income
Accounting policy
Income is not recognised in the income statement until it is highly probable that the conditions attached to the income will be met.

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Deferred income	**138,095**	138,416

In December 2023 a farm-down of an equity interest in the EnQuest Producer FPSO and certain capital spares related to the Bressay development was completed and cash received of $141.3 million. The same amount was lent back to the acquirer in December 2023 as vendor financing (see note 18(f)). Proceeds from the farm-down are reported within deferred income, as these are contingent upon the Bressay development project achieving regulatory approval. Both parties are committed to delivering the development, however should the project not achieve regulatory approval there remains the option to deploy the assets on an alternative project.

25. Commitments and contingencies
Capital commitments
At 31 December 2024, the Group had commitments for future capital expenditure amounting to $13.3 million (2023: $43.8 million). The key components of this relate to commitments for the new stabilisation facility at Sullom Voe Terminal and Magnus 2025 drilling campaign. Where the commitment relates to a joint venture, the amount represents the Group's net share of the commitment. Where the Group is not the operator of the joint venture then the amounts are based on the Group's net share of committed future work programmes.

Other commitments
In the normal course of business, the Group will obtain surety bonds, Letters of Credit and guarantees. At 31 December 2024, the Group held surety bonds totalling $277.0 million (2023: $250.4 million) to provide security for its decommissioning obligations. See note 22 for further details.

Contingencies
The Group becomes involved from time to time in various claims and lawsuits arising in the ordinary course of its business. Outside of those already provided, the Group is not, nor has been during the past 12 months, involved in any governmental, legal or arbitration proceedings which, either individually or in the aggregate, have had, or are expected to have, a material adverse effect on the Group balance sheet or profitability. Nor, so far as the Group is aware, are any such proceedings pending or threatened.

A contingent payment of $15.0 million to Equinor is due upon regulatory approval of a Bressay field development plan.

26. Related party transactions
The Group financial statements include the financial statements of EnQuest PLC and its subsidiaries. A list of the Group's principal subsidiaries is contained in note 28 to these Group financial statements.

Balances and transactions between the Company and its subsidiaries, which are related parties, have been eliminated on consolidation and are not disclosed in this note.

All sales to and purchases from related parties are made at normal market prices and the pricing policies and terms of these transactions are approved by the Group's management. With the exception of the transactions disclosed below, there have been no transactions with related parties who are not members of the Group during the year ended 31 December 2024 (2023: none).

Within the $150.0 million term loan, which was fully repaid in October 2024, Double A Limited, a company beneficially owned by the extended family of Amjad Bseisu, lent $9.0 million on the same terms and conditions as all other lending parties. This was considered a smaller related party transaction under Listing Rule 11.1.10 which ended on repayment of the term loan. Double A Limited's share of the early repayment fee was $0.3 million.

Compensation of key management personnel

The following table details remuneration of key management personnel of the Group. Key management personnel comprise Executive and Non-Executive Directors of the Company and the Executive Committee.

	2024 $'000	2023 $'000
Short-term employee benefits	**5,138**	5,360
Share-based payments	**124**	144
Post-employment pension benefits	**226**	241
Termination payments	**947**	367
	6,435	6,112

27. Risk management and financial instruments

Risk management objectives and policies

The Group's principal financial assets and liabilities comprise trade and other receivables, cash and cash equivalents, interest-bearing loans, borrowings and leases, derivative financial instruments and trade and other payables. The main purpose of the financial instruments is to manage cash flow and to provide liquidity for organic and inorganic growth initiatives.

The Group's activities expose it to various financial risks particularly associated with fluctuations in oil price, foreign currency risk, liquidity risk and credit risk. The Group is also exposed to interest rate risks related to SOFR on cash balances and the RBL. As the RBL was undrawn at 31 December 2024, no sensitivities have been provided. Management reviews and agrees policies for managing each of these risks, which are summarised below. Also presented below is a sensitivity analysis to indicate sensitivity to changes in market variables on the Group's financial instruments and to show the impact on profit and shareholders' equity, where applicable. The sensitivity has been prepared for periods ended 31 December 2024 and 2023, using the amounts of debt and other financial assets and liabilities held at those reporting dates.

Commodity price risk – oil prices

The Group is exposed to the impact of changes in Brent oil prices on its revenues and profits generated from sales of crude oil.

The Group's policy is to have the ability to hedge oil prices up to a maximum of 75% of the next 12 months' production on a rolling annual basis, up to 60% in the following 12-month period and 50% in the subsequent 12-month period. On a rolling quarterly basis, under the RBL facility, the Group is required to hedge a minimum of 45% of volumes of net entitlement production expected to be produced in the next 12 months, and between 35% and 15% of volumes of net entitlement production expected for the following 12 months dependent on the proportion of the facility that is utilised. This requirement ceases at the end date of the facility.

Details of the commodity derivative contracts entered into during and open at the end of 2024 are disclosed in note 18. As of 31 December 2024, the Group held financial instruments (options and swaps) related to crude oil that covered 4.4 MMbbls of 2025 production and 1.3 MMbbls of 2026 production. The instruments have an effective average floor price of around $69/bbl in both 2025 and 2026. The Group utilises multiple benchmarks when hedging production to achieve optimal results for the Group. No derivatives were designated in hedging relationships at 31 December 2024.

The following table summarises the impact on the Group's pre-tax profit of a reasonably possible change in the Brent oil price on the fair value of derivative financial instruments, with all other variables held constant. The impact in equity is the same as the impact on profit before tax.

	Pre-tax profit	
	+$10/bbl increase $'000	-$10/bbl decrease $'000
31 December 2024	**(47,600)**	**47,200**
31 December 2023	(4,000)	7,400

Foreign exchange risk

The Group is exposed to foreign exchange risk arising from movements in currency exchange rates. Such exposure arises from sales or purchases in currencies other than the Group's functional currency and the 9.00% retail bond and any UK EPL cash tax payments which is denominated in Sterling. To mitigate the risks of large fluctuations in the currency markets, the hedging policy agreed by the Board allows for up to 70% of the non-US Dollar portion of the Group's annual capital budget and operating expenditure to be hedged. For specific contracted capital expenditure projects, up to 100% can be hedged. Approximately 12% (2023: 22%) of the Group's sales and 97% (2023: 95%) of costs (including operating and capital expenditure and general and administration costs) are denominated in currencies other than the functional currency.

The Group also enters into foreign currency swap contracts from time to time to manage short-term exposures. The following tables summarise the Group's financial assets and liabilities exposure to foreign currency.

Year ended 31 December 2024	**GBP $'000**	**MYR $'000**	**Other $'000**	**Total $'000**
Total financial assets	**219,758**	**22,570**	**3,024**	**245,352**
Total financial liabilities	**455,128**	**21,731**	**3,801**	**480,661**

Year ended 31 December 2023	GBP $'000	MYR $'000	Other $'000	Total $'000
Total financial assets	241,844	42,233	954	285,031
Total financial liabilities	479,819	9,801	1,295	490,915

The following table summarises the sensitivity to a reasonably possible change in the US Dollar to Sterling foreign exchange rate, with all other variables held constant, of the Group's profit before tax due to changes in the carrying value of monetary assets and liabilities at the reporting date. The impact in equity is the same as the impact on profit before tax. The Group's exposure to foreign currency changes for all other currencies is not material:

	Pre-tax profit	
	10% rate increase $'000	10% rate decrease $'000
31 December 2024	**(19,956)**	**19,956**
31 December 2023	(20,398)	20,398

Credit risk
Credit risk is managed on a Group basis. Credit risk in financial instruments arises from cash and cash equivalents and derivative financial instruments where the Group's exposure arises from default of the counterparty, with a maximum exposure equal to the carrying amount of these instruments. For banks and financial institutions only those rated with an A-/A3 credit rating or better are accepted. Cash balances can be invested in short-term bank deposits and AAA-rated liquidity funds, subject to Board-approved limits and with a view to minimising counterparty credit risks.

In addition, there are credit risks of commercial counterparties, including exposures in respect of outstanding receivables. The Group trades only with recognised international oil and gas companies, commodity traders and shipping companies and at 31 December 2024, there were no trade receivables past due but not impaired (2023: nil) and no joint venture receivables past due but not impaired (2023: nil). Receivable balances are monitored on an ongoing basis with appropriate follow-up action taken where necessary. Any impact from ECL is disclosed in note 15.

Ageing of past due but not impaired receivables	2024 $'000	2023 $'000
Less than 30 days	**–**	–
30–60 days	**–**	–
60–90 days	**–**	–
90–120 days	**–**	–
120+ days	**–**	–
	–	–

At 31 December 2024, the Group had two customers accounting for 91% of outstanding trade receivables (2023: one customer, 58%) and four joint venture partners accounting for over 70% of outstanding joint venture receivables (2023: no joint venture partner).

Liquidity risk
The Group monitors its risk of a shortage of funds by reviewing its cash flow requirements on a regular basis relative to its existing bank facilities and the maturity profile of its borrowings. Specifically, the Group's policy is to ensure that sufficient liquidity or committed facilities exist within the Group to meet its operational funding requirements and to ensure the Group can service its debt and adhere to its financial covenants. At 31 December 2024, $194.3 million (2023: $166.2 million) was available for drawdown under the Group's facilities (see note 17).

The following tables detail the maturity profiles of the Group's non-derivative financial liabilities, including projected interest thereon. The amounts in these tables are different from the balance sheet as the table is prepared on a contractual undiscounted cash flow basis and includes future interest payments.

The payment of contingent consideration is limited to cash flows generated from Magnus (see note 21). Therefore, no contingent consideration is payable if insufficient cash flows are generated over and above the requirements to operate the asset and there is no exposure to liquidity risk. By reference to the conditions existing at the reporting period end, the maturity analysis of the contingent consideration is disclosed below. All of the Group's liabilities, except for the RBL, are unsecured.

Year ended 31 December 2024	On demand $'000	Up to 1 year $'000	1 to 2 years $'000	2 to 5 years $'000	Over 5 years $'000	Total $'000
Loans	**–**	**34,168**	–	–	–	**34,168**
Bonds	**–**	**69,095**	**69,095**	**701,197**	–	**839,387**
Contingent consideration	**–**	**20,675**	**64,877**	**265,854**	**425,027**	**776,433**
Obligations under lease liabilities	**–**	**66,092**	**71,600**	**222,093**	**31,696**	**391,481**
Trade and other payables	**–**	**414,390**	–	–	–	**414,390**
	–	**604,420**	**205,572**	**1,189,144**	**456,723**	**2,455,859**

Year ended 31 December 2023	On demand $'000	Up to 1 year $'000	1 to 2 years $'000	2 to 5 years $'000	Over 5 years $'000	Total $'000
Loans	–	64,518	131,081	221,311	–	416,910
Bonds	–	50,749	50,749	576,415	–	677,913
Contingent consideration	–	46,555	95,335	289,823	393,187	824,900
Obligations under lease liabilities	–	160,341	70,062	229,310	36,322	496,035
Trade and other payables	–	347,408	13,167	19,750	–	380,325
	–	669,571	360,394	1,336,609	429,509	2,796,083

The following tables detail the Group's expected maturity of payables for its derivative financial instruments. The amounts in these tables are different from the balance sheet as the table is prepared on a contractual undiscounted cash flow basis. When the amount receivable or payable is not fixed, the amount disclosed has been determined by reference to a projected forward curve at the reporting date.

Year ended 31 December 2024	**On demand $'000**	**Less than 3 months $'000**	**3 to 12 months $'000**	**1 to 2 years $'000**	**Over 2 years $'000**	**Total $'000**
Commodity derivative contracts	**–**	**546**	**8,908**	**999**	**–**	**10,453**
Foreign exchange derivative contracts	**–**	**1,105**	**1,249**	**–**	**–**	**2,354**
Other derivative contracts	**–**	**23,902**	**3,802**	**1,928**	**–**	**29,632**
	–	**25,553**	**13,959**	**2,927**	**–**	**42,439**

Year ended 31 December 2023	On demand $'000	Less than 3 months $'000	3 to 12 Months $'000	1 to 2 years $'000	Over 2 years $'000	Total $'000
Commodity derivative contracts	414	3,111	17,264	1,000	–	21,789
Other derivative contracts	–	8,261	–	–	–	8,261
	414	11,372	17,264	1,000	–	30,050

Capital management

The capital structure of the Group consists of debt, which includes the borrowings disclosed in note 17, cash and cash equivalents and equity attributable to the equity holders of the parent company, comprising issued capital, reserves and retained earnings as in the Group statement of changes in equity.

The primary objective of the Group's capital management is to optimise the return on investment, by managing its capital structure to achieve capital efficiency whilst also maintaining flexibility for downside protection and growth initiatives. The Group regularly monitors the capital requirements of the business over the short, medium and long term, in order to enable it to foresee when additional capital will be required.

The Group has approval from the Board to hedge external risks, see Commodity price risk: oil prices and foreign exchange risk. This is designed to reduce the risk of adverse movements in exchange rates and market prices eroding the return on the Group's projects and operations.

The Board regularly reassesses the existing dividend policy to ensure that shareholder value is maximised. Any future shareholder distributions are expected to depend on the earnings and financial condition of the Company and such other factors as the Board considers appropriate.

The Group monitors capital using the gearing ratio and return on shareholders' equity as follows. Further information relating to the movement year-on-year is provided within the relevant notes and within the Financial review (page 11).

	2024 $'000	2023 $'000
Loans, borrowings and bond(i) (A) (see note 17)	**666,073**	794,453
Cash and cash equivalents (see note 13)	**(280,239)**	(313,572)
EnQuest net debt (B) (ii)	**385,834**	480,881
Equity attributable to EnQuest PLC shareholders (C)	**542,466**	456,728
Profit/(loss) for the year attributable to EnQuest PLC shareholders (D)	**93,773**	(30,833)
Adjusted EBITDA (F) (ii)	**672,585**	824,666
Gross gearing ratio (A/C)	**1.2**	1.7
Net gearing ratio (B/C)	**0.7**	1.1
EnQuest net debt/adjusted EBITDA (B/F) (ii)	**0.6**	0.6
Shareholders' return on investment (D/C)	**17.3%**	N/A

(i) Principal amounts drawn, excludes netting off of fees and accrued interest (see note 17)
(ii) See Glossary – non GAAP measures on page 70

28. Subsidiaries

At 31 December 2024, EnQuest PLC had investments in the following subsidiaries:

Name of company	Principal activity	Country of incorporation	Proportion of nominal value of issued ordinary shares controlled by the Group
EnQuest Britain Limited	Intermediate holding company and provision of Group manpower and contracting/procurement services	England	100%
EnQuest Heather Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Thistle Limited(i)4	Exploration, extraction and production of hydrocarbons	England	100%
Stratic UK (Holdings) Limited(i)4	Intermediate holding company	England	100%
EnQuest ENS Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest UKCS Limited(i)4	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Heather Leasing Limited(i)	Leasing	England	100%
EQ Petroleum Sabah Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Dons Leasing Limited(i)	Leasing	England	100%
EnQuest Energy Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Production Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Global Limited	Intermediate holding company	England	100%
EnQuest NWO Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EQ Petroleum Production Malaysia Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
NSIP (GKA) Limited1	Dormant	Scotland	100%
EnQuest Global Services Limited(i)2	Provision of Group manpower and contracting/procurement services for the international business	Jersey	100%
EnQuest Marketing and Trading Limited	Marketing and trading of crude oil	England	100%
NorthWestOctober Limited(i)4	Dormant	England	100%
EnQuest UK Limited(i)4	Dormant	England	100%
EnQuest Petroleum Developments Malaysia SDN. BHD(i)3	Exploration, extraction and production of hydrocarbons	Malaysia	100%
EnQuest NNS Holdings Limited(i)4	Intermediate holding company	England	100%
EnQuest NNS Limited(i)4	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Advance Holdings Limited(i)	Intermediate holding company	England	100%
EnQuest Advance Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Forward Holdings Limited(i)4	Intermediate holding company	England	100%
EnQuest Forward Limited(i)4	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Progress Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
North Sea (Golden Eagle) Resources Ltd(i)	Exploration, extraction and production of hydrocarbons	England	100%
Veri Energy (CCS) Limited(i)	Assessment and development of new energy and decarbonisation opportunities	England	100%
Veri Energy (Hydrogen) Limited(i)	Assessment and development of new energy and decarbonisation opportunities	England	100%
Veri Energy Holdings Limited	Intermediate holding company	England	100%
Veri Energy Limited(i)	Assessment and development of new energy and decarbonisation opportunities	England	100%

(i) Held by subsidiary undertaking

The Group has two branches outside the UK (all held by subsidiary undertakings): EnQuest Global Services Limited (Dubai) and EnQuest Petroleum Production Malaysia Limited (Malaysia).

Other than those listed below, all entities have a registered office address as Charles House, 2nd Floor, 5-11 Regent Street, London, SW1Y 4LR United Kingdom.

1 Annan House, Palmerston Road, Aberdeen, Scotland, AB11 5QP, United Kingdom
2 Ground Floor, Colomberie House, St Helier, JE4 0RX, Jersey
3 c/o TMF, 10th Floor, Menara Hap Seng, No. 1 & 3, Jalan P. Ramlee 50250 Kuala Lumpur, Malaysia
4 c/o BDO LLP, Temple Square Temple Street Liverpool L2 5RH - indicates those legal entities that formally entered into the liquidation process during October 2024

29. Cash flow information

Cash generated from operations

	Notes	**Year ended 31 December 2024 $'000**	Year ended 31 December 2023 $'000
Profit/(loss) before tax		**166,614**	231,779
Depreciation	4(c)	**6,040**	6,109
Depletion	4(b)	**263,252**	292,199
Exploration and appraisal expense		**183**	5,640
Net impairment charge to oil and gas assets	9	**71,414**	117,396
Net (write back)/disposal of inventory		**(5,539)**	(622)
Share-based payment charge	4(e)	**983**	3,320
Change in Magnus related contingent consideration	21	**15,904**	(10,811)
Change in provisions	22	**39,116**	59,970
Other non-cash income	4(d)	**–**	(4,058)
Change in Golden Eagle related contingent consideration	21	**–**	1,663
Unrealised (gain)/loss on commodity financial instruments	4(a)	**(3,090)**	(28,463)
Unrealised loss/(gain) on other financial instruments	4(b)	**2,823**	3,832
Unrealised exchange (gain)/loss		**(8,714)**	12,401
Net finance expense		**113,711**	140,213
Operating cashflow before working capital changes		**662,697**	830,568
(Increase)/decrease in trade and other receivables		**(4,561)**	51,724
(Increase)/decrease in inventories		**(5,786)**	(9,518)
Increase/(decrease) in trade and other payables		**33,596**	(18,028)
Cash generated from operations		**685,946**	854,746

Changes in liabilities arising from financing activities

	Loans and borrowings $'000	**Bonds $'000**	**Lease liabilities $'000**	**Total $'000**
At 1 January 2023	(413,528)	(597,283)	(482,066)	(1,492,877)
Cash movements:				
Repayments of loans and borrowings	289,684	138,052	–	427,736
Proceeds from loans and borrowings	(190,657)	–	–	(190,657)
Payment of lease liabilities	–	–	135,675	135,675
Cash interest paid in year	36,285	62,130	–	98,415
Non-cash movements:				
Additions	–	–	(28,377)	(28,377)
Interest/finance charge payable	(30,708)	(58,999)	(43,801)	(133,508)
Fee amortisation	(1,476)	(3,091)	–	(4,567)
Foreign exchange and other non-cash movements	(810)	(11,828)	(3,605)	(16,243)
At 31 December 2023	(311,210)	(471,019)	(422,174)	(1,204,403)
Cash movements:				
Repayments of loans and borrowings(i)	**312,304**	–	–	**312,304**
Proceeds from loans and borrowings(ii)	**(26,928)**	**(160,000)**	–	**(186,928)**
Payment of lease liabilities	–	–	**130,065**	**130,065**
Cash interest paid in year(iii)	**18,524**	**52,494**	–	**71,018**
Non-cash movements:				
Additions	–	**3,362**	**(16,453)**	**(13,091)**
Interest/finance charge payable	**(18,524)**	**(54,971)**	**(27,673)**	**(101,168)**
Fee amortisation	**(5,036)**	**(3,493)**	–	**(8,529)**
Foreign exchange and other non-cash movements	**(3,102)**	**2,742**	**980**	**620**
At 31 December 2024	**(33,972)**	**(630,885)**	**(335,255)**	**(1,000,112)**

(i)Repayments of loans and borrowings include $140.0 million repaid under the RBL facility, $150.0 million term loan repayment and $22.3 million repaid under the SVT working capital facility (note 17). In the Group Cash Flow Statement, the repayment of loans and borrowings line does not include the term loan repayment. This was fully repaid utilising the proceeds from the high yield bond tap and as such is netted against the proceeds of the high yield bond tap in the Group Cash Flow Statement on the proceeds from loans and borrowings line

(ii)Proceeds from loans and borrowing include $26.9 million draw-downs under the SVT working capital facility and $160.0 million high yield bond tap. In the Group Cash Flow Statement, proceeds from loans and borrowings of $31.7 million includes amounts outlined in the table above less the term loan repayment of $150.0 million, associated fees on termination $4.7 million and $0.4m relating to the high yield bond issue premium net of issue fees. See note 17 for further details

(iii) The cash flow statement includes interest on decommissioning bonds and Letters of Credit

Reconciliation of carrying value

	Loans (see note 17) $'000	Bonds (see note 17) $'000	Lease liabilities (see note 23) $'000	Total $'000
Principal	(319,784)	(474,669)	(422,174)	(1,216,627)
Unamortised fees	8,553	10,724	–	19,277
Accrued interest	21	(7,074)	–	(7,053)
At 31 December 2023	(311,210)	(471,019)	(422,174)	(1,204,403)
Principal	**(33,972)**	**(632,101)**	**(335,255)**	**(1,001,328)**
Unamortised fees	–	**10,661**	–	**10,661**
Accrued interest	**–**	**(9,445)**	**–**	**(9,445)**
At 31 December 2024	**(33,972)**	**(630,885)**	**(335,255)**	**(1,000,112)**

30. Subsequent events

In January 2025, EnQuest announced that it had signed a Sale and Purchase Agreement to acquire Harbour Energy's business in Vietnam, which includes the 53.125% equity interest in the Chim Sáo and Dua production fields. These fields are governed by the Block 12W Production Sharing Contract, which runs to November 2030 with an opportunity to extend. The transaction has an effective date of 1 January 2024 and is scheduled to complete during the second quarter of 2025. The headline value of the transaction is $84.0 million and, net of interim period cash flows, the consideration to be paid by EnQuest on completion is expected to equal c. $35 million. As at 1 January 2025, net 2P reserves and 2C resources across the fields total 7.5 million boe and 4.9 million boe, respectively.

Glossary – Non-GAAP Measures

The Group uses Alternative Performance Measures ('APMs') when assessing and discussing the Group's financial performance, balance sheet and cash flows that are not defined or specified under IFRS but consistent with accounting policies applied in the financial statements. The Group uses these APMs, which are not considered to be a substitute for, or superior to, IFRS measures, to provide stakeholders with additional useful information to aid the understanding of the Group's underlying financial performance, balance sheet and cash flows by adjusting for certain items, as set out below, which impact upon IFRS measures or, by defining new measures.

As set out in note 2, the Group no longer separately presents business performance results and remeasurements and exceptional items. However, the Group continues to adjust for material items consisting of income and expense within its APMs which, because of the nature or expected infrequency of the events giving rise to them or they are items which are remeasured on a periodic basis, merit separate presentation to allow shareholders to understand better the elements of financial performance in the year, so as to facilitate comparison with prior periods and to better assess trends in financial performance.

Adjusting items include, but are not limited to:

- Unrealised mark-to-market changes in the remeasurement of open derivative contracts at each period end;
- Impairments on assets, including other non-routine write-offs/write-downs where deemed material;
- Fair value accounting arising in relation to business combinations. These transactions, and the subsequent remeasurements of contingent assets and liabilities arising on acquisitions, including contingent consideration, do not relate to the principal activities and day-to-day underlying business performance of the Group; and
- Other items that arise from time to time that are reviewed by management and considered to require separate presentation.

In considering the tax on exceptional items, the Group applies the appropriate statutory tax rate to each item to calculate the relevant tax charge on exceptional items.

Adjusted net profit attributable to EnQuest PLC shareholders (i)	2024 $'000	2023 $'000
Net profit/(loss) (A)	**93,773**	(30,833)
Adjustments – remeasurements and exceptional items :		
Unrealised gains on derivative contracts (note 18)	**267**	24,631
Net impairment (charge)/reversal to oil and gas assets (note 9, note 10 and note 11)	**(71,414)**	(117,396)
Change in Magnus contingent consideration (notes 4(d))	**(15,904)**	10,811
Movement in other provisions (notes 4(b) and note 4(d)	**–**	(1,717)
Insurance income on Kraken shutdown and PM8/Seligi riser incident (see note 4(d))	**1,663**	4,127
Write-off of exploration costs (see note 4(d))	**(183)**	(5,640)
Drilling rig contract regret costs (see note 4(d))	**(14,629)**	–
Pre-tax remeasurements and exceptional items (B)	**(100,200)**	(85,184)
Tax on remeasurements and exceptional items (C)	**58,760**	25,138
Post-tax remeasurements and exceptional items (D = B + C)	**(41,440)**	(60,046)
Adjusted net profit attributable to EnQuest PLC shareholders (A – D)	**135,213**	29,213

(i) APM changed from Business performance net profit to adjusted net profit, which have been calculated on a consistent basis

Adjusted EBITDA is a measure of profitability. It provides a metric to show earnings before the influence of accounting (e.g. depletion and depreciation), financial deductions (e.g. borrowing interest) and other adjustments set out in the table below. For the Group, this is a useful metric as a measure to evaluate the Group's underlying operating performance and is a component of a covenant measure under the Group's reserve based lending ('RBL') facility. It is commonly used by stakeholders as a comparable metric of core profitability and can be used as an indicator of cash flows available to pay down debt. Due to the adjustment made to reach adjusted EBITDA, the Group notes the metric should not be used in isolation. The nearest equivalent measure on an IFRS basis is profit/(loss) before tax and finance income/(costs).

Adjusted EBITDA	2024 $'000	2023 $'000
Reported profit from operations before tax and finance income/(costs)	**311,528**	397,373
Adjustments:		
Unrealised gains on derivative contracts (note 18)	**(267)**	(24,631)
Net impairment charge/(reversal) to oil and gas assets (note 9, note 10 and note 11)	**71,414**	117,396
Change in Magnus contingent consideration (notes 4(d))	**15,904**	(10,811)
Insurance income on Kraken and PM8/Seligi riser incident (see note 4(d))	**(1,663)**	(4,127)
Write-off of exploration costs (see note 4(d))	**183**	5,640
Drilling rig contract regret costs (see note 4(d))	**14,629**	–
Depletion and depreciation (note 4(b) and note 4(c))	**269,292**	298,308
Inventory revaluation	**(5,539)**	(622)
Change in decommissioning and other provisions (note 4(b) and note 4(d))	**7,078**	34,481
Net foreign exchange (gain)/loss (note 4(d))	**(9,975)**	11,659
Adjusted EBITDA (E)	**672,584**	824,666

Total cash and available facilities is a measure of the Group's liquidity at the end of the reporting period. The Group believes this is a useful metric as it is an important reference point for the Group's going concern and viability assessments, see page 16.

Total cash and available facilities	2024 $'000	2023 $'000
Available cash	**226,317**	313,028
Restricted cash	**53,922**	544
Total cash and cash equivalents (F) (note 13)	**280,239**	313,572
Available credit facilities[(i)]	**248,356**	518,794
Credit facility – drawn down	**–**	(290,000)
Letter of credit - utilised (note 17)	**(54,100)**	(43,545)
Available undrawn facility (G)	**194,256**	185,249
Total cash and available facilities (F + G)	**474,495**	498,821

[(i)]Includes amounts available under the RBL: $176.4 million (2023: $306.2 million), letters of credit: $54.1 million (2023: $43.5 million), term loan: $nil (2023: $150.0 million), vendor loan facility providing capacity for refinancing the payment of existing invoices up to an amount of £23.7 million: $17.9 million available (2023: $19.0 million in relation to a vendor loan facility which expired on 1 January 2024)

Net debt is a liquidity measure that shows how much debt a company has on its balance sheet compared to its cash and cash equivalents. It is an important reference point for the Group's going concern and viability assessments, see page 16. The Group's definition of net debt, referred to as EnQuest net debt, excludes unamortised fees, accrued interest and the Group's lease liabilities as the Group's focus is the management of cash borrowings and a lease is viewed as deferred capital investment.

EnQuest net debt	2024 $'000	2023 $'000
Loans and borrowings (note 17):		
RBL facility	**–**	135,080
Term loan facility	**–**	146,367
SVT working capital facility	**33,972**	29,784
Bonds (note 17):		
High yield bond	**454,339**	294,276
Retail bond	**167,101**	169,669
Accrued interest	**9,445**	–
Loans and borrowings (H)	**664,857**	463,945
Non-cash accounting adjustments (note 17):		
Unamortised fees on loans and borrowings	**–**	8,553
Unamortised fees on bonds	**10,661**	10,724
Accrued interest	**(9,445)**	–
Non-cash accounting adjustments (I)	**1,216**	19,277
Debt (H + I) (J)	**666,073**	794,453
Less: Cash and cash equivalents (note 13) (F)	**280,239**	313,572
EnQuest net debt (J – F) (K)	**385,834**	480,881

The EnQuest net debt/adjusted EBITDA metric is a ratio that provides management and users of the Group's consolidated financial statements with an indication of the Group's ability to settle its debt. This is a helpful metric to monitor the Group's progress against its strategic objective of maintaining balance sheet discipline.

EnQuest net debt/adjusted EBITDA	**2024 $'000**	2023 $'000
EnQuest net debt (K)	**385,834**	480,881
Adjusted EBITDA (E)	**672,585**	824,666
EnQuest net debt/adjusted EBITDA (K/E)	**0.6**	0.6

Cash capital expenditure (nearest equivalent measure on an IFRS basis is purchase of property, plant and equipment) monitors investing activities on a cash basis, while cash decommissioning expense monitors the Group's cash spend on decommissioning activities. The Group provides guidance to the financial markets for both these metrics given the materiality of the work programme.

Cash capital and decommissioning expense	**2024 $'000**	2023 $'000
Reported net cash flows (used in)/from investing activities	**(183,573)**	(262,695)
Adjustments:		
Purchase of other intangible assets	**1,138**	876
Payment of Magnus contingent consideration – Profit share	**48,466**	65,506
Payment of Golden Eagle contingent consideration – Acquisition costs	**–**	50,000
Proceeds from vendor financing facility receipt	**(107,518)**	**–**
Proceeds from Bressay farm-down	**(1,263)**	**–**
Interest received	**(10,101)**	(5,895)
Cash capital expenditure	**(252,851)**	(152,208)
Decommissioning expenditure	**(60,544)**	(58,911)
Cash capital and decommissioning expense	**(313,395)**	(211,119)

Adjusted free cash flow ('FCF') represents the cash a company generates, after accounting for cash outflows to support operations and to maintain its capital assets. It excludes movements in loans and borrowings, net proceeds from share issues, the impact of acquisitions and disposals and shareholder distributions. Currently, this metric is useful to management and users to assess the Group's ability to allocate capital across a range of activities – including investment shareholder distributions, transactions and debt management.

Adjusted free cash flow	**2024 $'000**	2023 $'000
Net cash flows from/(used in) operating activities	**508,769**	754,244
Adjustments:		
Purchase of property, plant and equipment	**(249,165)**	(141,741)
Purchase of oil and gas and other intangible assets	**(4,824)**	(11,343)
Payment of Magnus contingent consideration	**(48,466)**	(65,506)
Estimated cash tax on disposal proceeds(i)	**50,000**	–
Interest received	**10,101**	5,895
Payment of obligations under finance lease	**(130,065)**	(135,675)
Interest paid	**(83,162)**	(105,877)
Adjusted Free cash flow	**53,188**	299,997

(i) Estimated by reference to disposal proceeds of $141.4 million and the EPL tax rate of 35%

Average realised price is a measure of the revenue earned per barrel sold. The Group believes this is a useful metric for comparing performance to the market and to give the user, both internally and externally, the ability to understand the drivers impacting the Group's revenue.

Revenue sales	**2024 $'000**	2023 $'000
Revenue from crude oil sales (note 4(a)) (L)	**1,020,266**	1,127,419
Revenue from gas and condensate sales (note 4(a))	**164,647**	338,973
Realised (losses)/gains on oil derivative contracts (note 4(a)) (M)	**(12,907)**	(11,264)

Barrels equivalent sales	**2024 kboe**	2023 kboe
Sales of crude oil (N)	**12,554**	13,714
Sales of gas and condensate(i)	**2,400**	4,107
Total sales	**14,954**	17,821

(i) Includes volumes related to onward sale of third-party gas purchases not required for injection activities at Magnus

Average realised prices	2024 $/Boe	2023 $/Boe
Average realised oil price, excluding hedging (L/N)	**81.3**	82.2
Average realised oil price, including hedging ((L + M)/N)	**80.2**	81.4

Operating costs ('opex') is a measure of the Group's cost management performance (reconciled to reported cost of sales, the nearest equivalent measure on an IFRS basis). Opex is a key measure to monitor the Group's alignment to its strategic pillars of financial discipline and value enhancement and is required in order to calculate opex per barrel (see below).

Operating costs	2024 $'000	2023 $'000
Total cost of sales (note 4(b))	**787,383**	946,752
Adjustments:		
Unrealised (losses)/gains on derivative contracts related to operating costs (note 4(b))	**(2,823)**	(3,832)
Movement in contractor dispute provision note 4(d)	**–**	(1,818)
Depletion of oil and gas assets (note 4(b))	**(263,252)**	(292,199)
(Charge)/credit relating to the Group's lifting position and inventory (note 4(b))	**(2,172)**	4,244
Other cost of operations(i) (note 4(b))	**(136,318)**	(305,919)
Operating costs	**382,818**	347,228
Less: realised (losses)/gains on derivative contracts (P) (note 4(b))	**(4,735)**	2,839
Operating costs directly attributable to production	**378,083**	350,067
Comprising of:		
Production costs (Q) (note 4(b))	**307,634**	308,331
Tariff and transportation expenses (R) (note 4(b))	**70,449**	41,736
Operating costs directly attributable to production	**378,083**	350,067

(i) Includes $125.7 million (2023: $294.0 million) of purchases and associated costs of third-party gas not required for injection activities at Magnus, which is sold on

Barrels equivalent produced	2024 kboe	2023 kboe
Total produced (working interest) (S)(i)	**14,909**	**15,992**

(i) Production 724 kboe associated with Seligi gas (2023: 220 kboe)

Unit opex is the operating expenditure per barrel of oil equivalent produced. This metric is useful as it is an industry standard metric allowing comparability between oil and gas companies. Unit opex including hedging includes the effect of realised gains and losses on derivatives related to foreign currency and emissions allowances. This is a useful measure for investors because it demonstrates how the Group manages its risk to market price movements.

Unit opex	2024 $/Boe	2023 $/Boe
Production costs (Q/S)	**20.6**	19.3
Tariff and transportation expenses (R/S)	**4.7**	2.6
Total unit opex ((Q + R)/S)	**25.3**	21.9
Realised loss/(gain) on derivative contracts (P/S)	**0.3**	(0.2)
Total unit opex including hedging ((P + Q+ R)/S)	**25.6**	21.7