EnQuest PLC, 25 March 2026

Results for the year ended 31 December 2025 and 2026 outlook

Unless otherwise stated, all figures are in US Dollars.
Comparative figures for the Income Statement relate to the year ended 31 December 2024 and the Balance Sheet as at 31 December 2024.
Alternative performance measures are reconciled within the 'Glossary – Non-GAAP measures' at the end of the Financial Statements.

EnQuest Chief Executive, Amjad Bseisu, said:

"In a volatile world, EnQuest stands out for its consistent operational delivery, highly tangible reserves base, disciplined investment, and a strategy anchored in diversified growth. Our position as a top quartile operator, combined with a strengthened financial base and an increasingly diversified portfolio, sets the stage for a pivotal period of growth across the UK North Sea and South East Asia.

2025 was a busy year, in which we grew and diversified our operations. Asset uptime averaged c.90%, and we grew production by 5.4% to deliver above the upper end of our market guidance. We lowered our unit operating costs despite a significant weakening of the US Dollar, and we executed multiple fast-payback production investments. We grew rapidly in South East Asia, integrating our new Vietnam business, bringing Seligi 1b gas onstream (Malaysia) nine months ahead of schedule, and we were awarded licences in Brunei and Indonesia.

In Q4 2025, we also refinanced our RBL, strengthening our banking group and unlocking $200 million of additional liquidity (cash and undrawn facilities totalling $679 million at 31 Dec 2025). The RBL and EnQuest's broader credit positioning have since been further enhanced by the $60.0 million settlement of the Magnus contingent consideration mechanism, which removes a $432.9 million balance sheet liability and unlocks for EnQuest c.$777 million in additional undiscounted forward Magnus cash flow.

These actions ensured that we began 2026 with confidence and momentum. Reflecting strong Peninsular Malaysia gas demand and robust well performance, Seligi 1b is regularly delivering up to 40% above the field's contracted volumes, and, having resolved third-party disruption to Magnus (due to extreme North Sea weather), Group production has consistently exceeded 50 Kboed during March. With production enhancement investment programmes scheduled for the balance of the year, we reiterate our annual guidance target of 41 to 45 Kboed.

As we work to maximise the value of our existing assets, accelerate our expansion in South East Asia, and use our advantaged UK tax position and operating expertise to execute a material UK North Sea transaction, we expect that continued successful delivery will be transformative, broadening our production base, increasing cash flow and enhancing shareholder returns.

"Reflecting the resilience of our core business and our commitment to sustainable shareholder returns, the Board has proposed an increased final 2025 dividend of approximately $20.0 million, subject to shareholder approval."

2025 performance

- EnQuest operates 97% of its asset portfolio, and in 2025, the Group delivered another year of top quartile performance.
  - Production of 45,606 Boepd (including pro forma Vietnam volumes) was above the top end of market guidance (pro forma 40,000 to 45,000 Boepd). Underlying asset uptime of 89% was at the top end of sector performance.
  - Reported production for the year, which includes Vietnam volumes from 9 July, was 42,945 Boepd (2024: 40,736 Boepd).
- 2P reserves totalled 162.5 MMboe (2024: 168.6 MMboe) at year end; 78% of which are in the highly tangible 1P (proven) volume category.
- Investment in fast payback projects grew and diversified production, whilst lowering unit costs and reducing emissions.
  - UK production remained within 4% of 2024 volumes. Magnus output rose 8%, to 15.3 Kboed, despite a five-week third-party infrastructure outage. Excluding this outage, North Sea production efficiency was 92%.
  - In July, EnQuest completed the acquisition of Harbour Vietnam. EnQuest has already undertaken three proactive well investments at Block 12W, boosting net average Q4 production to c.5.5 Kboed.
  - South East Asian production grew 13% year-on-year, and in December 2025 EnQuest commenced gas production from Seligi 1b (Malaysia), nine months ahead of schedule. Full production (c.70 mmscf/d, 6.0 Kboed net) began in January 2026.
- EnQuest became the first company to be named Malaysia Operator of the Year in consecutive years at the PETRONAS Emerald Awards. EnQuest was also recognised with an award for Abandonment Excellence in Malaysia.
- New country entries enhance diversified growth across South East Asia, targeting c.35 Kboed in net production in the region by 2030.
  - Brunei Darussalam - awarded operatorship of the Block C PSC in July, where EnQuest plans to deliver c.15 Kboed of gas production by 2029 (structured around a 50:50 JV with the Brunei government).
  - Indonesia - awarded operatorship and a 40% interest in the Gaea and Gaea II PSCs in August. With prospectivity of more than 100 Tcf across multiple prospects, and the bp Tangguh partnership a 40% partner, the blocks are well positioned to access LNG markets.

Financial highlights

- Reserve Based Lending facility refinanced in Q4 2025. Backed by eight leading banks, the $800 million facility provides significant transactional capacity ($400 million loan tranche) and simplifies management of UK decommissioning security ($400 million letter of credit tranche). Both tranches can be increased by $400 million, via an $800 million accordion.
- With the RBL fully undrawn at year end, cash and available facilities totalled $678.6 million (31 December 2024: $474.5 million).

- EnQuest net debt of $433.9 million (31 December 2024: $385.8 million) followed payment in H2 2025 of UK EPL tax of $104.1 million; $22.7 million on completion of the Vietnam acquisition and RBL refinancing fees totaling $17.8 million.
  - Revenue and other income totalled $1,118.3 million (2024: $1,180.7 million), with adjusted EBITDA of $503.8 million (2024: $673.9 million). Both figures reflect lower oil revenues, with Brent falling 15% year-on-year. Cost discipline and active hedging held operating costs flat, despite a 10% weakening of the US Dollar.
  - Net $238.9 million gain on settlement of the Magnus contingent consideration simplifies EnQuest's balance sheet.
  - Reported profit after tax of $1.6 million (2024: $93.8 million) includes the impact of the two-year extension of EPL. Stripping out this non-cash item, the profit after tax would have been $125.5 million.
  - Capital investment $179.2 million (2024: $252.9 million), inclusive of c.$40 million in Seligi 1b growth capex. Decommissioning expenditure $56.8 million (2024: $60.5 million), focused on well plugging and abandonment and Heather topsides removal.
  - The Group declared its maiden dividend of c.$15 million, which was paid in June 2025.

2026 outlook

- EnQuest is focused on delivering continued operational excellence and value-accretive transactions in the UK and in South East Asia.
  - Credit-enhancing settlement of the Magnus contingent consideration, completed in February for $60.0 million.
  - By crystallising payments that would otherwise have been payable over time (valued at $432.9 million on a discounted basis at 30 June 2025), this settlement unlocks the full upside of one of the Group's core assets.
  - A six-well Magnus infill drilling programme and production-enhancing well interventions are due to commence in Q2 2026.
- Net Group production is expected to average between 41,000 and 45,000 Boepd.
  - Production to end February averaged 32,429 Boepd, including the deferral of c.650 kbbls (c.11,000 Boepd) due to a five-week third-party infrastructure outage at Magnus. In March, Group production has consistently exceeded 50,000 Boepd.
  - In Malaysia, EnQuest is producing increased Seligi gas volumes to support rising and sustained Peninsular Malaysia demand. March gross gas volumes have regularly reached c.100 mmscf/d, materially exceeding the nominated contract volume of 70 mmscf/d.
- Operating expenditure expected to total c.$450 million; capital investment expected to total c.$160 million; Decommissioning expenditure expected to total c.$60 million.
- From 1 April 2026, EnQuest has hedged a total of 5.1 MMbbls for the next 12 months with an average floor price of $71.3/bbl and a further 3.5 MMbbls in the subsequent 12-month period with an average floor price of $64.4/bbl, predominantly utilising swaps.
- The Group is pleased to propose a 2025 final dividend of 0.8 pence per share, equivalent to c.$20 million, payable in June 2026 following shareholder approval at the Group's Annual General Meeting.

Production and financial information

Macro conditions	2025	2024	Change
Brent oil price[4] ($/bbl)	68.2	80.5	-15.3%
Natural gas price[5] (GBp/Therm)	88.3	83.6	+5.6%

Alternative performance measures ('APMs')	2025	2024	Change
Production (Boepd)	42,945	40,736	5.4%
Realised oil price ($/bbl)[1,2]	68.8	80.2	-14.2%
Average unit operating costs ($/Boe)[2]	25.1	25.6	-2.0%
Adjusted EBITDA ($m)[2]	503.8	673.9	-25.2%
Cash expenditures ($m)	236.0	313.4	-24.7%
Capital[2]	179.2	252.9	-29.1%
Decommissioning	56.8	60.5	-6.1%
Adjusted free cash flow ($m)[2]	8.7	53.2	-83.6%

	End 2025	End 2024	
EnQuest net (debt)/cash ($m)[2]	(433.9)	(385.8)	12.5%

Statutory measures	2025	2024	Change %
Reported revenue and other operating income ($m)[3]	1,118.3	1,180.7	-5.3%

Cost of sales ($m)	(837.5)	(787.4)	6.4%
Reported gross profit ($m)	280.8	393.3	-28.6%
Reported profit/(loss) after tax ($m)	1.6	93.8	-98.3%
Reported basic earnings/(loss) per share (cents)	0.1	5.0	-82.0%
Net cash flow from operating activities ($m)	362.7	507.6	-28.5%
Net increase/(decrease) in cash and cash equivalents ($m)	(24.5)	(27.7)	11.6%

Notes:
[1] Including realised gains of $8.7 million (2024: realised losses of $12.9 million) associated with EnQuest's oil price hedges
[2] See reconciliation of alternative performance measures within the 'Glossary – Non-GAAP Measures' starting on page 61.
[3] Including net realised and unrealised gains of $53.9 million (2024: net realised and unrealised losses of $9.8 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 10:30 today – London time, via Investor Meet Company.

The presentation is open to all existing and potential shareholders. Questions can be submitted pre-event via your Investor Meet Company dashboard, 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 unlocking value from energy assets. Responsibly. As an independent energy company with operations in the UK North Sea and across South East Asia, the Group's strategic vision is to lead as a safe, efficient operator of mature and underinvested oil and gas assets; sustainably extending field lives and delivering superior value across the asset lifecycle, as part of a just energy 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

A year defined by operational excellence, enhanced foundations and strategic clarity

Against a backdrop of geopolitical volatility, elevated commodity prices and macroeconomic uncertainty, EnQuest is focused on operational, financial and commercial delivery to maximise the value of our asset portfolio, expand scale and diversify our operations.

We are building on strong foundations. In 2025, our operational and financial performance was robust, and we simplified and enhanced our balance sheet.

At a time when the UK fiscal regime remains challenging, we also took decisive steps to accelerate our diversification into high-growth Asian markets.

Having accelerated the Seligi 1b gas project through targeted investment, we are now providing increased volumes to support Peninsular Malaysia demand, driving Group production above 50,000 Boepd in March.

Accordingly, we have entered 2026 confident in our people, our relationships and our assets, and with enhanced financial strength. With cash and undrawn facilities totalling $678.6 million, we are well-positioned in both the UK North Sea and South East Asia to deliver both organic and acquisitional growth.

Delivering safe, reliable performance across our portfolio

EnQuest delivered another impressive operational year. Group production exceeded the top end of our 40-45 Kboed pro forma guidance range at 45,606 Boepd, including the impact of our Vietnam acquisition. Underpinned by our operational expertise, Group production efficiency remained high at around 90%, and we continued to build on our track record of extracting value from late-life assets.

- The Kraken field continued to perform at the very top of the production efficiency for floating hubs, the FPSO's 95% production efficiency exceeding North Sea average efficiency by c.28%.
- Magnus increased year-on-year production by 8%, despite the impact of a five-week third-party infrastructure outage in the first half. 2025 uptime, excluding the third-party outage, was 93%, and the asset team completed a successful two-infill well drilling campaign.
- Settlement of the Magnus contingent consideration mechanism significantly enhances our balance sheet and demonstrates our long-term commitment to this core asset.
- In Malaysia, we expanded production by c.13%, with 93% production efficiency, and the benefit of new infill wells, idle well reinstatements and strong domestic gas demand.
- The nine-month acceleration of the Seligi 1b gas project exemplified our ability to enhance asset value, and we have continued to action modifications which further optimise gas production potential. Thus far in 2026, we have regularly provided more than 100 mmscf/d of gas to support Peninsular Malaysian demand, exceeding contractually nominated volumes by c.40%.
- With 452 MMboe of 2C resources in place at 31 December 2025, we continue to develop pathways to mature contingent resources into the 2P category.
- We successfully integrated our Vietnam acquisition and immediately deployed our operating expertise, proactively completing three well workovers that enhanced production in the second half of 2025.
- EnQuest also continued to advance its programme of decommissioning, completing the well campaigns at both Thistle and Heather, and removing Heather's topsides in a single 15.3 kTonne lift.

I was proud that in 2025 EnQuest was again named Malaysia Operator of the Year by PETRONAS, becoming the first operator to win this award in successive years. In 2025, EnQuest also became the first company to be awarded the Offshore Energies UK 'Excellence in Decommissioning' award twice.

These successes reflect a capability we consider core to our identity and how we create value: the ability to operate complex assets efficiently, safely and responsibly, through the full asset lifecycle.

Strategic progress: diversifying the portfolio and expanding our footprint
We also made significant strides in broadening our geographic and commodity exposure.

The accelerated expansion of our Seligi gas agreement and new country entries into Vietnam (through the Block 12W acquisition), Brunei Darussalam (via the Block C PSC award), and Indonesia (through the Gaea and Gaea II exploration blocks), all advance our strategy to develop a balanced portfolio anchored in predictable, high-quality operations.

Post-year end, we received a Letter of Award for a participating interest in the Cendramas PSC as part of the 2026 Malaysia Bid Round, further demonstrating our reputation as a highly respected counterparty across the region.

These strategic steps underpin the Group's expectation that at least 35 Kboepd of net production will come from South East Asia operations by 2030.

Financial discipline enabling shareholder returns and future growth
Global macroeconomic conditions in 2025 were shaped by uncertainty around US trade policy, risks to economic growth and the likelihood of excess crude supply. Brent crude prices remained subdued throughout the year, averaging in the mid $60s to low $70s per barrel.

2025 revenue and other operating income was c.5% lower year-on-year, primarily driven by a 15% decrease in oil prices, but EnQuest maintained stable production costs and delivered adjusted EBITDA of $503.8 million.

Post-tax profit of $1.6 million reflects the sector-wide impact of the UK government's decision in 2024 to extend the Energy Profits Levy ('EPL') by two years to 31 March 2030. Stripping this non-cash adjustment out, post tax profit was $125.5 million.

Our commitment to cost control, efficiency and capital discipline meant that the Group delivered on its cost guidance, despite the pressures arising from a material weakening in the US Dollar. I was also pleased that in June 2025, EnQuest paid its first dividend, returning $15.3 million to shareholders.

In the fourth quarter of 2025, the Group executed a refinancing of our Reserve Based Lending ('RBL') facility, establishing a six-year facility totalling $800.0 million. Supported by eight leading international banks, including long-standing existing lenders and high-quality new relationships, the new RBL provides significant transactional capacity via the $400.0 million loan tranche and simplifies management of UK North Sea decommissioning security through the $400.0 million letter of credit tranche. An accordion of up to $800.0 million allows each tranche to increase by up to $400.0 million.

This facility, and the broader credit positioning of EnQuest, are further enhanced by the recent settlement of the Magnus contingent consideration. The $60.0 million settlement removes a $432.9 million liability from our balance sheet, unlocking for EnQuest c.$777 million in additional undiscounted forward Magnus cash flow.

With greater financial flexibility and a strengthened balance sheet, the Board is pleased to propose a dividend of 0.8 pence per share for 2025.

Navigating a shifting geopolitical landscape
Current geopolitical tensions underline the continued reliance of the world economy on hydrocarbons and the strategic importance for countries to have their own domestic oil and gas supply, the current closure of the Strait of Hormuz causing oil prices to spike above $100/bbl for the first time since 2022.

The volatility of current conditions reinforces the importance of EnQuest's focus on disciplined capital allocation, operational excellence and continued diversification of our portfolio. Our focus remains on extracting value from our core North Sea and South East Asian assets while maintaining financial resilience in a market characterised by underlying modest demand growth and elevated supply. This macroeconomic environment underscores the strategic importance of pursuing value-accretive opportunities that strengthen cash flow and support long-term shareholder returns.

The UK remains a fiscal outlier among nations by persisting in taxing windfall profits, even when prices have been below historic averages. This has impacted confidence in the UK North Sea, with operators cutting investment, accelerating the cessation of production on assets, and consolidating activities in what they consider to be a non-core region into joint ventures.

Although the UK Government missed an opportunity to stimulate sector investment in its 2025 Autumn Budget by continuing to apply the Energy Profit Levy, the formulation of the Oil and Gas Price Mechanism ('OGPM') as a permanent, fit-for-purpose windfall tax successor to EPL offers encouragement. EnQuest sees the OGPM as a positive development for the sector, balancing increased taxation during periods of elevated prices with an environment that does not discourage investment. EnQuest continues to advocate for the accelerated introduction of the OGPM, ahead of the current EPL sunset date of 31 March 2030.

The deployment of our operational expertise and advantaged fiscal position remain very relevant to the UK North Sea, and we are confident they provide a strong foundation from which to consolidate value.

In Asia, the value proposition for EnQuest is simple and clear. Every country in which we operate is a growth economy, and each is structurally short energy. We are well respected in the region, with a strong track record of delivery. As we expand our operational footprint and deploy our differentiated capabilities, we stand ready to meet the growing demands of the economies and communities we serve.

Building a lower-carbon future while maintaining safe operations
EnQuest is an expert in building value in mature and underinvested oil and gas assets, and we strongly believe that everything we do directly contributes to a just and economic transition to a lower-carbon future.

We continue to make strong progress against our environmental commitments. Since the 2018 baseline established by the NSTA's North Sea Transition Deal ('NSTD'), we have reduced our absolute UK Scope 1 and 2 emissions by more than 45%, providing a strong foundation for our commitment to reach net zero in Scope 1 and Scope 2 emissions by 2040. As a result, we are tracking well ahead of NSTD milestones and are closing in on the 2030 targeted reduction of 50%.

Work is ongoing to decarbonise existing portfolio infrastructure, including the project to reduce Kraken fuel and flare through the development of the Bressay gas cap, and two major transformation projects at the Sullom Voe Terminal, including the New Stabilisation Facility and long-term power solution, which together are expected to reduce terminal emissions by around 90%. We also remain the most active decommissioning operator in the UK North Sea, delivering safe and efficient decommissioning across multiple major projects. Importantly, we continue to build this expertise while the majority of the cost of these activities is paid by the companies from which we acquired our assets.

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.

Our transition plan is credible, and I was proud to see EnQuest awarded an A- rating in the 2025 CDP Climate Change Survey, reflecting the Group's strong governance, robust emissions management, and clear, transparent strategy to manage climate-related risks and opportunities. EnQuest's A- was the single highest score awarded globally within the oil and gas extraction and production sector, making EnQuest the only company in this category to receive CDP's leadership-level recognition.

Safety remains our top priority and licence to operate. I am pleased to say that we saw a significant decrease in Lost Time Incidents during 2025, returning to a level that significantly outperformed the North Sea average. We are not complacent in this, however, and we are reinforcing our expectations with employees and contractors to ensure that everyone working at an EnQuest site is aligned with our commitment to SAFE Results.

Looking ahead: a transformational year for EnQuest
In 2026, our ambition is clear: maximise the value of our existing assets, continue our disciplined expansion in South East Asia, and use our advantaged UK tax position and operating expertise to execute a material UK North Sea transaction. We expect that successful delivery against these value-led targets will be transformative, broadening our production base, increasing cash flow and enhancing shareholder returns.

Production to the end of February averaged 32,429 Boepd, including the deferral of c.650 kbbls of Magnus production due to a third-party infrastructure outage, caused by storm damage. Since full production was reinstated at Magnus, Group production has consistently exceeded 50,000 Boepd, giving us confidence that we will again deliver against our annual targets.

To proactively address the risk of third-party equipment downtime on Magnus production, EnQuest is well advanced with plans to bypass the Ninian Central Platform during 2027, securing Magnus' offtake route into the future.

Our position as a top quartile operator, combined with a strengthened financial base and an increasingly diversified portfolio, sets the stage for a pivotal period of growth.

Closing remarks
2025 showcased what EnQuest does best: delivering top-quartile operations, employing disciplined financial management, and unlocking value. We enter 2026 with momentum, financial strength and a clear strategic direction. I remain immensely proud of our people, whose commitment and expertise underpin every success.

As we pursue a material UK transaction and continued international expansion, we will remain guided by a single priority: delivering long-term value for our shareholders while playing a responsible role in the evolving energy landscape.

Operational review

2025 saw the Group deliver 89% production efficiency across its operated portfolio.
EnQuest continues to demonstrate its differentiated operating capability, founded on deep expertise in late-life asset management and complemented by sector-leading decommissioning performance.

In all our activities, the safety and well-being of those working across EnQuest's sites remains paramount. All personnel are empowered to act decisively to ensure the Group's high standards of safe operations are consistently upheld.

The Group remains focused on optimising the assets it operates and has an established track record of extending the productive life of mature oil and gas fields. This is achieved through disciplined maintenance programmes, the effective management of critical production infrastructure, and the high-quality execution of drilling and well intervention activities.

In parallel, EnQuest continues to progress initiatives to decarbonise its portfolio. Projects at Magnus, Kraken and the Sullom Voe Terminal ('SVT') are aimed at materially reducing the Group's carbon footprint while improving the long-term cost base of our operations. These initiatives are an important component in ensuring the Group's assets remain resilient and competitive within an evolving regulatory environment.

As part of maximising value from operated assets, the Group recognises the importance of planning and executing safe, efficient and cost-effective decommissioning, typically beginning around five years ahead of the cessation of asset production. Decommissioning is an increasingly important capability for operators in mature basins worldwide, and one in which EnQuest is demonstrating sector leadership.

The operational excellence in evidence across EnQuest's portfolio is transferable and scalable, supporting the Group's growth ambitions both in the UK North Sea and across South East Asia. It also underpins the Group's plans to right-size and repurpose existing infrastructure, including the development of SVT as a future decarbonisation and renewable energy hub.

Operational excellence

In delivering production uptime of 89% across its operated portfolio during 2025, EnQuest achieved a level of performance that sits at the very top end of the UK North Sea sector.

Excluding the impact of a third-party infrastructure outage, which saw Magnus production shut-in for five weeks, Group production efficiency was 92%.

The latest available benchmarked data from the North Sea Transition Authority ('NSTA') shows that production efficiency across the UKCS is 75%. EnQuest's UK operated asset uptime was 87%.

Further, the NSTA UKCS production efficiency for floating hubs is 67%. At 95% production efficiency, EnQuest's Kraken FPSO beats that by 28%.

This exemplary uptime performance extends to the Group's South East Asia business, with 93% uptime at PM8/Seligi and 100% uptime in Vietnam.

UK Upstream

2025 UK operations performance summary

Production of 31,122 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, offsetting the impact of natural field declines.

Kraken

2025 performance summary

The Kraken Floating, Production, Storage and Offloading ('FPSO') facility delivered an exceptional production efficiency of 95% (2024: 96%) and water injection efficiency of 93% (2024: 95.5%) for the year, resulting in average 2025 net production of 10,948 Boepd (2024: 12,759 Boepd). This is a testament to the focus and collaboration between the EnQuest and Bumi Armada operational teams, delivering production efficiency performance that is 28% above the industry average benchmark for floating hubs (as measured against the latest North Sea Transition Authority data).

The Kraken maintenance shutdown was deferred to 2026 to enable isolation upgrades that will reduce the production impact associated with future planned maintenance. 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.

2026 outlook

The asset team is focused on maintaining best-in-class FPSO production efficiency through focused investment in maintenance and reliability activities, while aiming to manage reservoir decline and fuel gas production with water injection sweep optimisation. Work is ongoing to mature the Kraken Enhanced Oil Recovery ('EOR') project during 2026. Following an initial round of polymer testing, further work is ongoing to ensure the compatibility of reservoir chemicals with topside process equipment. EOR represents a material upside to Kraken's value, with base case incremental recoverable oil estimates of more than 40 MMbbls gross.

The EnQuest team is also advancing a fuel gas import project that involves the subsea tie-back of a Bressay gas well to the Kraken FPSO. By establishing an alternative 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. Significant progress has been made in aligning the technical development scenario with the NSTA, and both a Bressay FDP and a Kraken FDPA are at an advanced stage.

With c.33 MMboe of 2C resources, and Harbour Energy expected to replace Waldorf as our field partner, EnQuest 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 2026, Kraken production will be subject to natural field decline and the impact of a short maintenance "pit-stop" shutdown planned in the third quarter of the year, which has been reduced from 15 days through planned upgrades to isolations between the two production trains.

Magnus

2025 performance summary

In 2025, Magnus delivered an 8% increase in asset production, achieving 15,335 Boepd (2024: 14,173 Boepd) despite a five-week third-party infrastructure outage in the first half of the year. The annualised impact of this outage was c.1.7 Kboed in deferred production; equivalent to the volume lifted within a standard Magnus offtake. The production increase was underpinned by exceptional production efficiency of 93% (2024: 83%) excluding third-party downtime, and the proactive completion of key maintenance scopes during the production shut-in meant that the seven-day maintenance shutdown originally planned for the second half of the year was not required.

2025 asset production benefitted from a successful two-well infill drilling programme, with both wells producing above mid-case expectations, well interventions and well optimisation work. The period June to August 2025 saw EnQuest deliver the best three-monthly oil production rate at Magnus since early 2020, peaking at c.19 Kboed barrels of oil per day in mid-July. In addition, the recommissioning of a fifth water injection pump provided a 20% uplift in Magnus water injection capacity, with field average water cut reduced back to 2017 pre-acquisition levels of around 85%.

2026 outlook
The Group plans to execute a six-well infill drilling programme at Magnus, commencing in May 2026 and culminating in 2027. The programme includes well targets in the Lower Kimmeridge Clay Formation ('LKCF') reservoir, which is estimated to contain c.325 million barrels of oil in place. The Group is targeting 10 MMbbls of production upside from the next production phase at the LKCF. 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.

Storm damage at the third-party operated Ninian Central Platform ('NCP') resulted in a five-week unplanned outage for all system users, including Magnus, at the start of 2026. Production was reinstated on 22 February.

EnQuest is proactively addressing the risk of third-party equipment unavailability to Magnus production and is progressing plans to facilitate a bypass of NCP during 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 Emissions Reduction project in Q4 2024, engineering work will continue in 2026. This project demonstrates EnQuest's commitment to the decarbonisation of its portfolio.

Greater Kittiwake Area
2025 performance summary
At the Greater Kittiwake Area ('GKA'), 2025 production averaged 1,825 Boepd (2024: 2,009 Boepd), largely in line with expectations. Solid operational performance in the year was underpinned by production efficiency of 75% (2024: 77%) and included the efficient completion of the planned maintenance shutdown.

2026 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, and in parallel with 2026 production operations. This process will be managed in full by EnQuest, with Shell having transferred its decommissioning operator role to EnQuest during 2024.

Non-operated North Sea assets
2025 performance summary
2025 production across the Group's non-operated UK interests averaged 3,014 Boepd (2024: 3,646 Boepd), with asset performance continuing in line with the Group's expectations.

2026 outlook
At Golden Eagle, a 41-day shutdown is planned during the third quarter.

At Alba, the most significant activity centres on decommissioning, with the cessation of asset production planned during the summer.

South East Asia

PM8/Seligi, Malaysia

2025 performance summary
EnQuest was again named Malaysia Operator of the Year at the 2025 PETRONAS Emerald Awards, becoming the first company to receive this prestigious accolade in successive years. To be recognised in this way by PETRONAS is an important validation of the Group's reputation as a top-tier operator, both in Malaysia and across the South East Asia region and is a testament to the work undertaken across the EnQuest Malaysia team.

Malaysian production averaged 9,201 Boepd, 12.9% higher than 2024. This increase was driven by continued operational excellence and production efficiency of 93% (2024: 94%), as well as a programme of infill drilling, idle well restoration and well workovers.

Following the award of an expansion to its Seligi gas agreement, EnQuest has successfully accelerated plans 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.

Demonstrating the Group's project delivery expertise, work to drill recompletions on five existing wells and execute infrastructure modifications was completed nine months ahead of schedule, with gas production beginning in December 2025. EnQuest commenced full production at 70 mmscf/d in January 2026, with capacity now proven to increase gross production to c.100 mmscf/d, supporting Peninsular Malaysian demand and helping the nation meet its growing energy needs. These volumes also increase the gas component of EnQuest's production, which aligns with the Group's strategic aim to reduce its overall carbon intensity.

The EnQuest Malaysia decommissioning team was also recognised with an award for Abandonment Excellence at the PETRONAS Emerald Awards, following the successful execution of a six-well plugging and abandonment ('P&A') campaign during 2024. In 2025, EnQuest completed the P&A of a further five wells, with work commencing following the Seligi gas workover programme. This takes the total number of completed P&A wells in Malaysia to 21.

EnQuest continued its excellent HSE performance in Malaysia during 2025, reaching the milestones of over three years and seven million man-hours without a lost time incident.

2026 outlook
The Group plans to drill further non-associated gas wells during 2026, as well as a programme of well workover and idle well restoration activities.

A nine-day 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.

At DEWA, which is located around 60km offshore Sarawak, Malaysia, the Group's operated acreage includes 12 discovered fields with significant gas development potential. EnQuest is targeting a phased development, with Phase 1 expected to deliver net production of c.9 Kboed and c.28 MMboe of net reserves. The Field Development and Abandonment Plan ('FDAP') and Final Investment Decision ('FID') are planned for the second half of 2026, subject to joint venture partner and regulatory reviews and approvals.

EnQuest received a Letter of Award ('LOA') for a participating interest in the Cendramas PSC by Petronas. The terms of the LOA, subject to the finalisation and signing of the Joint Operating Agreement and the Cendramas PSC, are effective from 23 September 2026, with more details on the PSC to be provided upon signing.

Block 12W, Vietnam

2025 performance summary
In July 2025, EnQuest completed the acquisition of Harbour Energy's business in Vietnam, including a 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 had an effective date of 1 January 2024, with a headline value of $85.1 million. Net of interim period cash flows, the consideration paid by EnQuest was $25.7 million.

Having assumed operatorship of the Chim Sáo and Dua fields ('Block 12W') from completion, EnQuest is deploying its proven late-life and FPSO asset management expertise to maximise value and is working to progress discovered resources into reserves. The Group executed three proactive well investments in the second half of 2025, boosting net average production in the fourth quarter to c.5.5 Kboed. Reported net production, on an annualised basis, was 2,622 Boepd, while pro forma production for 2025 was 5,283 Boepd. EnQuest has delivered 100% production efficiency since taking over as operator.

2026 outlook
Having already enhanced production since assuming operatorship of the Chim Sáo and Dua fields in July 2025, the PSC extension provides EnQuest and its joint venture partners with the opportunity to access upside across Block 12W and progress discovered resources into reserves, with prospectivity spread across three gas discoveries and several additional targets.

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. In Vietnam, EnQuest has been successful in extending the Block 12W PSC by four years to July 2034, on its existing terms.

Decommissioning

Performance summary
EnQuest's dedicated in-house decommissioning team delivered a landmark year in 2025, reinforcing its position as a leader in North Sea decommissioning. All well plug and abandonment ('P&A') activities have now been successfully completed at Heather and Thistle, marking a significant milestone in these projects and a major step in the safe and efficient retirement of these offshore assets. The Heather topsides were safely removed from the field, while preparations for Thistle's removal progressed at pace, setting the stage for the next phase of heavy-lift operations.

These achievements underscore EnQuest's commitment to operational excellence and environmental responsibility as it continues to execute complex multi-asset campaigns ahead of schedule and within budget.

Well decommissioning
Between 2022 and 2024, the latest period for which NSTA data is available, EnQuest has completed 47% of all Northern and Central North Sea well P&A activity, at a cost that is significantly below the basin average.

At both the Heather and Thistle fields, all P&A activities were completed after three-and-a-half-year campaigns on each asset, with a total of 83 successfully abandoned. In 2025, the Thistle team executed the remaining seven wells to Phase 2, with the main rig then recovering 11 conductors. The remaining 13 conductors were recovered offline during a multi-year conductor-pulling unit campaign. At Heather, the well P&A campaign was completed in March 2025, with a total of 34 conductors successfully removed by the main rig.

Throughout 2025, EnQuest has also progressed planning and engineering work on the Kittiwake platform wells and subsea wells at Magnus and Alma Galia, while continuing to discuss the future work programmes with the North Sea Transition Authority.

Preparation for removal
Alongside the completion of P&A at Heather, the project team completed final preparations in readiness for the Allseas Pioneering Spirit vessel campaign to remove the topsides.

The Heather team disembarked safely from the platform, completing the asset rundown efficiently following well P&A. Key tasks included cleaning the topsides and utility rundown. The Allseas Oceanic CSV then carried out the required leg-cutting work ahead of the arrival of the Pioneering Spirit heavy-lift vessel. In August the Pioneering Spirit mobilised, lifted the Heather topside, and offloaded it at the MARS disposal yard in Denmark.

At Thistle, the project team continued to demonstrate its ability to deliver multiple key scopes simultaneously. EnQuest and Saipem teams worked closely together, advancing engineering and planning for the pre-disembarkation preparation phase, which commenced in April and continued throughout the year, ahead of the future heavy-lift campaigns.

Subsea campaigns were also completed, covering essential inspection, repair and maintenance activities, as well as conductor recovery, utilising a bespoke conductor drill and pinning tool designed specifically for the Thistle campaign.

2025 marked the final full year on the platform, with disembarkation planned for the first half of 2026, upon completion of the extensive pre-disembarkation preparations scope and platform run-down.

Asset removals
In 2025, significant preparatory work was completed, and Heather was disembarked to allow Allseas and their Pioneering Spirit heavy lift vessel to remove the topsides from the field.

The Heather project reached a major decommissioning milestone, following the safe removal of the Heather Alpha topsides in August. The Allseas-owned Pioneering Spirit heavy lift vessel removed the 15,300 tonne topsides in a single lift; the largest single lift in the North Sea in 2025. The topsides were transported to Denmark where 97% of all decommissioning waste is to be reused or recycled.

The Heather jacket is scheduled for removal in 2027, which aligns with previously agreed contractual execution windows.

Midstream

Safe, stable operations
Throughout 2025, 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.

Decarbonisation
The Group is focused on right-sizing SVT for future operations. During 2025, EnQuest successfully advanced 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.

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, which will be retired once the grid connection is in place.

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 2025, EnQuest continued 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. A world-first scope involved the removal of a redundant crude oil tank with roof integrity issues, highlighting EnQuest's decommissioning expertise. Furthermore, the removal of the facilities creates the opportunity to repurpose areas of SVT for third-party use, including renewable energy projects.

2025 emissions at SVT were improved year-on-year, following a period of elevated flaring due to issues encountered with the site's gas compression system, which resulted in flaring above the routine baseline levels. Following the effective deployment of an engineering and repair solution, the compression system was returned to full operations, resulting in a return to lower process flaring and emissions. It should be noted that the impacted compressor will be retired when the NSF is operational.

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. In 2025 the numbers were increased with two apprentices in college and three working at the terminal gaining valuable experience in 2025. The Group also continued with its graduate programme in 2025, with one engineer successfully completing the EnQuest Graduate scheme at SVT.

SVT supported a range of cultural and sporting events in Shetland in 2025, including the Shetland Junior Golf Open and sponsorship of local table tennis events, Shetland Rugby Club U18 Italy tour and Shetland Folk Festival. SVT was proud to have sponsored Team Shetland and Ability Shetland to take part in the Disability Summer Games in Stirling, in which 19 athletes from Shetland took part.

Seven educational awards for the academic year 2024-2025 were made by the Trustees of the Sullom Voe Terminal Participants' Tenth Anniversary Fund. Now in its 37th 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 English language and linguistics, energy transitions and sustainability, mathematics and structural engineering.

As operator, EnQuest also offers a scholarship opportunity 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.

Electrification/Onshore wind
During 2024, Veri Energy identified and progressed an opportunity to develop an onshore wind project on behalf of EnQuest, designed to harness Shetland's exceptional wind resource to support decarbonisation and lower operating costs at the Sullom Voe Terminal. The project advanced through front-end engineering and design in 2025, with a final investment decision expected in 2026.

E-fuels
In early 2025, Veri Energy launched a major initiative to evaluate investable pathways for e-fuel production at Sullom Voe. Working with leading global technology providers, the team assessed and de-risked the full value chain for producing e-fuels from green hydrogen and biogenic CO2.

This work aims to unlock Scotland's potential to produce low-carbon fuels by also harnessing Shetland's exceptional wind resource and the inherent advantages of the terminal site, strengthening long-term energy security and resilience. Support from Aberdeen's Net Zero Technology Centre, through its Energy Hubs project, is enabling the development of an advanced operating model for future e-fuel facilities.

The assessment evaluated both methanol synthesis and Fischer–Tropsch pathways using market-leading technologies. Following this analysis, the first phase will prioritise the development of an e-methanol facility, with front-end engineering and design expected to begin in 2026. E-methanol was selected due to its strong applicability for marine decarbonisation and its role as a key feedstock for sustainable aviation fuel via methanol-to-jet technology.

Additional workstreams commencing in 2026 will explore replication of the e-methanol facility and future expansion into downstream e-SAF production.

With a skilled local workforce and advantaged site conditions, the Sullom Voe development has the potential to scale into a meaningful e-fuels export opportunity over time.

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 CO2 from isolated emitters in the UK and Europe. CO2 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 2025, work included significant engagement with the NSTA to progress the licences through early risk assessment and site characterisation, 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 CO2 emitters to permanently sequester carbon beginning in the early 2030s.

Financial review

Introduction

Against an uncertain macro-economic backdrop, EnQuest has used the tangibility of its hydrocarbon reserves and strength of its relationships to further simplify and strengthen its balance sheet. The Group has also managed its exposure to lower and more volatile oil prices and a weaker USD, through a combination of hedging programmes, cost control and liquidity management. These steps have enabled the Group to build a significant platform of liquidity – that can be used to deliver both organic and transformational growth.

In November, EnQuest successfully refinanced its Reserve Based Lending Facility (the 'RBL'). Structured around a $400.0 million loan tranche and $400.0 million letter of credit tranche, the new facility extends the instrument's maturity to 2031; expands Group total liquidity ($678.6 million at 31 December 2025; $474.5 million at 31 December 2024) and simplifies the management of decommissioning obligations. An accordion of up to $800.0 million provides the potential to increase each tranche by up to $400.0 million.

In December 2025, EnQuest reached substantial agreement with bp to settle the outstanding Magnus profit-share-related contingent consideration for $60.0 million (paid in February 2026). This credit enhancing transaction removes a material liability from EnQuest's balance sheet (which had a discounted value of $432.9 million at 30 June 2025) and opens significant additional RBL capacity. By securing full economic value to Magnus, EnQuest has enhanced its ability to optimise operational and strategic decisions over the life of the field, simplified its balance sheet and removed future financial variability associated with the mechanism.

To manage risk, EnQuest maintains a balanced programme of hedging. With average Brent declining 15% in 2025 and the USD weakening 10%, the Group's commodity and foreign exchange hedge programme delivered an aggregate $29.4 million of realised gains (2024: aggregate $10.0 million realised loss). From 1 April 2026, EnQuest has hedged a total of 5.1 MMbbls for the next 12 months with an average floor price of $71.3/bbl and a further 3.5 MMbbls in the subsequent 12-month period with an average floor price of $64.4/bbl, in each case predominantly utilising swaps.

The Group reported an IFRS post-tax profit of $1.6 million for the year to 31 December 2025 (2024: $93.8 million profit). Underlying this figure, settlement of the Magnus Contingent Consideration crystalised net other income of $391.3 million (pre-tax aggregate change in fair value of contingent consideration, see note 21) and a net impairment reversal of $5.8 million (2024: $71.4 million charge) was largely offset by the non-cash deferred tax charges of $152.4 million relating to the Magnus profit share settlement and the previously reported $123.9 million non-cash adjustment due to extension of the EPL 'windfall tax' by two years (from 31 March 2028 to 31 March 2030), lower underlying profit before tax (driven by lower oil prices) and a higher current year EPL tax charge of $84.1 million (2024: $10.3 million).

Free cash flow generation in the period was $8.7 million (2024: $53.2 million), reflecting lower oil revenues, higher UK tax payments and growth-focused capex programmes at Magnus and PM8/Seligi. After payments made in relation to the Group's maiden dividend, Vietnam acquisition and RBL refinancing fees, EnQuest net debt increased by $48.1 million, to $433.9 million. With the RBL fully undrawn at 31 December 2025, cash and available undrawn facilities were $678.6 million (31 December 2024: $474.5 million).

Income statement

Revenue

Group production averaged 42,945 Boepd, 5% higher than 2024. Underlying this was strong asset uptime performance of c.90%, the contribution from the acquisition of producing interests in Vietnam, and investment in low-cost, quick-payback well work and production optimisation at Magnus and PM8/Seligi. Partially offsetting these positives was a five-week shut in at Magnus, related to a third-party infrastructure outage and natural field declines. Oil accounted for 84.1% of this output (2024: 87.2%).

Brent crude oil prices declined 15% year-on-year to average $68.2/bbl (2024: $80.5/bbl) while the average day-ahead UK gas price increased by 5% to 88.3 GBp/therm (2024: 83.6 GBp/therm). Excluding the impact of hedging, EnQuest realised an average oil price of $68.1/bbl (2024: $81.3/bbl). Post-hedging, the realised oil price was $68.8/bbl (14.2% lower than in 2024, $80.2/bbl).

Reflecting the above price and volume drivers, Group revenue in the period totalled $1,118.3 million, a 5% reduction year-on-year (2024: $1,180.7 million). In this figure, oil contributed $858.2 million (16% lower year-on-year, 2024: $1,020.3 million) and condensate and gas revenue contributed $200.5 million (22% higher year-on-year, 2024: $164.6 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 offset through an equal and opposite charge to cost of sales.

Tariffs and other income generated $3.6 million (2024: $2.6 million), which includes income associated with the transportation of the initial Seligi 1a associated gas agreement.

Having repositioned and expanded the Group's programme of hedging in H2 2024, realised gains on commodity hedges in 2025 totalled $8.7 million, primarily reflecting the gains on swap contracts (2024: loss of $12.9 million). Unrealised gains on open commodity contracts (from mark-to-market movements) totalled $45.2 million (2024: $3.1 million gain).

Note: For the reconciliation of realised oil prices see 'Glossary – Non-GAAP measures' starting on page 61

Cost of sales

Reflecting the Group's South East Asian expansion, a weaker USD and higher volumes and prices associated with third-party West of Shetland gas that crosses the Magnus facility, cost of sales increased 6% to $837.5 million (2024: $787.4 million).

Excluding the impact of the 'crossover' gas volumes (2025: $166.2 million; 2024: $125.7 million), cost of sales was held broadly flat, with the Group's active foreign exchange hedging programme reinforcing the Group's continued focus on cost control.

Similarly, production growth and the weaker USD increased underlying production costs to $344.5 million (2024: $307.6 million). Inclusive of a $19.7 million net realised hedging gain (2024: net losses of $4.7 million) production costs increased by just 4%, with total operating costs up 3% at $394.0 million (2024: 382.8 million). Unit operating costs fell by 2% to $25.1/Boe (2024: $25.6/Boe).

	2025 $ million	2024 $ million
Production costs	**344.5**	307.6
Tariff and transportation expenses	**69.2**	70.5
Realised (gain)/loss on derivatives related to operating costs	**(19.7)**	4.7

Operating costs[1]	**394.0**	382.8
Charge/(credit) relating to the Group's lifting position and hydrocarbon inventory	**17.4**	2.2
Other cost of operations	**179.6**	135.0
Depletion of oil and gas assets	**267.3**	263.3
Other cost of sales	**(20.8)**	4.1
Cost of sales	**837.5**	787.4
Unit operating cost[2]	**$/Boe**	$/Boe
– Production costs	**22.0**	20.6
– Tariff and transportation expenses	**4.4**	4.7
Average unit operating cost (excluding gain/loss on derivatives)	**26.4**	25.3
Average unit operating cost (including gain/loss on derivatives)	**25.1**	25.6

Notes:
1 See reconciliation of alternative performance measures within the 'Glossary – Non-GAAP measures' starting on page 61
2 Calculated using production on a working interest basis including Seligi Associated Gas (1a)

The charge relating to the Group's lifting position and hydrocarbon inventory for the year ended 31 December 2025 was $17.4 million (2024: $2.2 million), reflecting the optimisation of oil sales from Magnus. Depletion expense ($267.3 million) was 2% higher than 2024 ($263.3 million), mainly reflecting the impact of the Vietnam acquisition, and other cost of sales ($20.8 million) reflects unrealised gains on foreign exchange and UKA forward contracts (2024: $4.1 million losses).

Impairment
In the year, the Group recognised a non-cash net impairment reversal of $5.8 million (2024: $71.4 million charge). Contributing to this, a reversal of $94.3 million at Kraken and an aggregate charge of $88.5 million for GKA, Golden Eagle and Alba, were primarily driven by a combination of a reduction in the discount rate to 9.0% (from 10.0% at 31 December 2024), reductions in near-term oil price assumptions (reflecting market dynamics) and updated production and cost profiles, including the impact of a weaker USD.

Other income and expenses
The Group recognised net other income in the period of $369.7 million (2024: net other expense of $4.7 million). The majority of this figure relates to a net $391.3 million non-cash credit that was triggered by EnQuest's agreement with bp to settle the outstanding Magnus profit share element of contingent consideration for $60.0 million (see note 21 for further detail). Lease income in the period totalled $20.4 million (2024: $16.5 million). Offsetting this income, was a non-cash foreign exchange revaluation loss of $28.3 million (2024: $10.0 million foreign exchange revaluation gain), with a $14.5 million non-cash net increase in the decommissioning provision of fully impaired non-producing assets (2024: non-cash charge of $7.1 million). 2024 also included a $14.6 million charge relating to the termination of a drilling rig contract, which followed Waldorf Petroleum's decision to defer near-term Kraken infill drilling, due to its financial circumstances.

Other expenses include costs associated with Veri Energy, which totalled $3.6 million in the year (2024: $1.7 million).

Adjusted EBITDA
Adjusted EBITDA for the year totalled $503.8 million, down 25% compared to the same period in 2024 ($673.9 million). This reduction primarily reflects changing production mix and lower oil revenue – driven by lower commodity prices (see detail above).

EnQuest's net debt to last 12-month adjusted EBITDA ratio at 31 December 2025 equalled 0.9x (31 December 2024: 0.6x).

Adjusted EBITDA	**2025 $ million**	2024 $ million
Profit/(loss) from operations before tax and finance income/(costs)	**648.8**	311.5
Net unrealised commodity, foreign exchange and UKA hedge (gain)/loss	**(77.5)**	(0.3)
Depletion and depreciation	**272.4**	269.3
Impairment (reversal)/charge	**(5.8)**	71.4
Change in fair value of contingent consideration	**(387.1)**	15.9
Net other expenses	**21.9**	21.6
Change in well inventories	**2.8**	(5.5)
Net foreign exchange revaluation loss/(gain)	**28.3**	(10.0)
Adjusted EBITDA[1]	**503.8**	673.9

Note:
1 See reconciliation of Adjusted EBITDA within the 'Glossary – Non-GAAP measures' starting on page 61

Finance costs
EnQuest's overall net finance costs increased by 7%, to $155.4 million (2024: $144.9 million).

Finance charges included interest on loans and borrowings of $75.3 million (2024: $73.5 million), the unwinding of discounting on decommissioning and other provisions (2025: $36.7 million; 2024: $31.2 million) and lease liability interest costs (2025: $25.1 million;

2024: $27.7 million). Refinancing fees, the amortisation of finance fees on loans and borrowings and other financial expenses (including the cost for surety bonds that provide security for decommissioning liabilities) totalled $27.5 million (2024: $27.1 million).

Finance income decreased to $9.2 million reflecting lower interest receivable from bank balances (2024: $14.5 million).

Profit/loss before tax
Reflecting the movements above, the Group's profit before tax was $493.4 million (2024: profit of $166.6 million).

Taxation
The 2025 tax charge of $491.9 million includes a non-cash deferred tax charge of $374.7 million and a current tax charge of $117.2 million.

As previously highlighted in the Group's results for the six months ended 30 June 2025, the deferred tax charge is heavily distorted by the non-cash impact of the two-year extension to the EPL; resulting in a charge to EnQuest of $123.9 million. The Group also recognised a further non-cash deferred tax charge of $152.4 million, which relates to the Magnus profit share settlement, and $98.4 million of other non-cash tax charges that reflect the utilisation of EnQuest's strategic UK North Sea tax asset in the period and tax on unrealised hedge gains.

The current cash tax charge, excluding prior year adjustments, includes $84.1 million related to the EPL (2024: $10.3 million), with the increase driven by lower capital expenditure and reduced EPL investment allowances, partly resulting from the abolishment of certain allowances from 1 November 2024.

The Group's income statement effective tax rate for the period was 99.7% (2024: 43.7%), with the two-year extension to the EPL constituting 25.1% of the Group's total 2025 effective tax rate.

EnQuest's strategic UK North Sea tax asset was estimated at $1,851.3 million (gross) at 31 December 2025 (31 December 2024: $2,066.4 million (gross)). The decrease reflects utilisation against UK upstream taxable profits.

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 EPL, noting however that the UK Government has indicated its intention to end EPL earlier than the current March 2030 legislated sunset date. In the Autumn Statement 2025, the UK Government announced that they will introduce the Oil and Gas Pricing Mechanism, a revenue-based windfall tax to replace EPL. EnQuest also pays cash corporate income tax on its Malaysian and Vietnam assets.

Profit/loss for the period
EnQuest's total profit after tax was $1.6 million (2024: profit after tax of $93.8 million). 2025 profit is heavily distorted by the significant non-cash impacts of the UK Government's decision in October 2024 to extend EPL by two years. Excluding this impact, EnQuest delivered an underlying profit for the period of $125.5 million.

Earnings per share
The Group's reported basic earnings per share was 0.1 cents (2024 earnings per share: 5.0 cents) and reported diluted earnings per share was 0.1 cents (2024 earnings per share: 4.9 cents).

Cash flow, EnQuest net debt and liquidity
Reported net cash flows from operating activities for the year were $362.7 million. This was 29% below the comparative period of 2024 ($507.6 million), which primarily reflects lower oil revenues due to the 15% year-on-year decline in Brent prices.

Reported net cash flows used in investing activities increased by $11.8 million, to $194.2 million. Whilst this figure includes the "one-off" acquisition cost of Vietnam ($20.3 million), the 2024 figure of $183.6 million included "one-off" receipts associated with the Bressay transaction of $108.8 million. Excluding these "one-off" items, net cash flows used in investing activities decreased by $117.3 million, principally reflecting $73.7 million lower capital expenditure (2025: $179.2 million; 2024: $252.9 million) and no Magnus profit share payments (2024: $48.5 million).

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

Capital expenditure	**2025** **$ million**	2024 $ million
North Sea	**128.0**	230.4
Malaysia and Vietnam	**48.5**	19.0
Exploration and evaluation	**2.7**	3.5
	179.2	252.9

The Group utilised $192.9 million of cash in financing activities (2024: $352.9 million). Interest payments on the Group's borrowings totalled $97.0 million (2024: $83.2 million). $83.1 million was paid in relation to finance leases (2024: $130.1 million), with the reduction versus 2024 primarily reflecting the c.70% contractual step down in charges relating to the Kraken FPSO, partially offset by lease payments associated with the Vietnam FPSO. In 2025, net borrowings totalled $6.0 million (2024: net repayments of $130.6 million). In the period, EnQuest also paid a maiden dividend, equivalent to $15.3 million (2024: share buyback of $9.0 million).

Despite significantly lower oil prices, EnQuest generated $8.7 million of adjusted free cash flow in 2025. This reflects higher cash tax payments and production enhancing investments, alongside management's focus on cost control, capital discipline and liquidity management. In aggregate, Group cash and cash equivalents decreased by $11.3 million to $268.9 million (2024: $280.2 million) and EnQuest net debt rose $48.1 million to $433.9 million (2024: $385.8 million). Primary drivers of this net debt rise were payment for the Vietnam acquisition ($20.3 million), payment of costs relating to the refinancing of the Group's RBL facility ($17.8 million) and EnQuest's inaugural dividend ($15.3 million).

The movement in EnQuest net debt was as follows:

	$ million
EnQuest net debt 1 January 2025	**(385.8)**

Net cash flows from operating activities	**362.7**
Cash capital expenditure	**(179.2)**
Net interest and finance costs paid	**(91.7)**
Finance lease payments	**(83.1)**
Dividend paid	**(15.3)**
Vietnam asset acquisition	**(20.3)**
RBL re-financing fees	**(17.8)**
Other movements, primarily net foreign exchange on cash and debt	**(3.4)**
EnQuest net debt 31 December 2025[1]	**(433.9)**

Note:
1 See reconciliation of alternative performance measures within the 'Glossary – Non-GAAP measures' starting on page 61

EnQuest net debt	**31 December 2025 $ million**	31 December 2024 $ million
Bonds	**644.4**	632.1
Senior secured debt facility ('RBL')	**-**	-
Vendor loan facility	**22.1**	-
SVT working capital facility	**36.3**	33.9
Cash and cash equivalents	**(268.9)**	(280.2)
EnQuest net debt[1]	**433.9**	385.8

Note:
1 See reconciliation of EnQuest net debt within the 'Glossary – Non-GAAP measures' starting on page 61

EnQuest continues to monitor the debt capital markets and would look to opportunistically refinance its existing 2027 bond maturities, subject to market conditions.

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 increased by 0.9% to $3,594.3 million (31 December 2024: $3,562.6 million). This was mainly driven by the acquisition of Vietnam assets, which contributed additional PP&E of $47.1 million and higher receivables of $152.5 million. The receivables were primarily associated with the Group's share of contributions already paid into the abandonment fund held in Vietnam (totalling $92.1 million) which was established to ensure that sufficient funds exist to meet future abandonment obligations (recorded in provisions as set out below) on Block 12W, partner share of the FPSO lease liability and other receivables. Other financial assets increased by $71.8 million, primarily reflecting mark-to-market gains on the Group's derivatives at 31 December 2025 (mark-to-market losses of $21.6 million at 31 December 2024 were shown in liabilities). The Group's deferred tax asset decreased by $235.1 million, primarily as a result of the tax effect of the change in fair value associated with the Magnus profit share contingent consideration and utilisation of the carry-forward tax loss position.

Liabilities
Total liabilities increased by 1.5% to $3,066.3 million (31 December 2024: $3,020.1 million). Decommissioning provisions increased by $174.0 million, reflecting $89.1 million additional obligations in Vietnam following the acquisition in July 2025 (offset by $92.1 million additional abandonment fund receivables noted above) (see notes 15 and 22) and in Malaysia related to the Seligi 1b gas project. Lease liabilities increased by $36.9 million, primarily reflecting the Vietnam FPSO lease obligations acquired, while trade and other payables also increased by $40.2 million, mainly in relation to the acquisition of Vietnam. Loans and borrowings increased by $42.6 million, reflecting drawdown of the vendor loan facility and foreign exchange movements on the GBP retail bond. Deferred tax liabilities increased by $145.7 million, primarily reflecting the impact on deferred tax from the two-year extension to the UK EPL. These increases were in turn offset by the agreement with bp to settle the Magnus profit share contingent consideration for $60.0 million, which led to a net reduction in the fair value estimate of $391.3 million, leaving a contingent consideration liability (including the Magnus-linked decommissioning liability) of $84.6 million (31 December 2024: $473.3 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 2025 Annual Report.

Going concern
During 2025, EnQuest has continued to focus on optimisation of its capital structure and the maximisation of its available transactional capacity.

In November, EnQuest signed a new six-year senior secured reserves-based lending facility which replaced the previous RBL, providing the Group with an enhanced capital structure that is simple, flexible and aligned with its growth ambitions. Details of the amended facility are provided in note 17. In February 2026, the Group made final settlement for the Magnus profit share contingent consideration, securing 100% of future Magnus cash flows while maintaining its limited exposure to future decommissioning expenditure at the asset. This credit-enhancing settlement, simplifies the Group's balance sheet, unlocks the full upside of one of EnQuest's core assets, and further secures longer term capacity under its RBL.

EnQuest closely monitors and manages its funding position and liquidity requirements throughout the year, including forecast covenant results. Cash forecasts are regularly produced and discussed, with 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. Management have considered the impact of the situation in the Middle East, particularly on future oil prices. Reflecting the uncertainty as to how long the conflict and the period of elevated oil prices will last, management have assumed in the Base Case that the average oil price for the going concern period will be $70.0/bbl. Although this is slightly higher than that used in its impairment assessment (see note 2) to reflect post year-end pricing trends, it is considerably below current spot prices.

The Group's latest approved budget and long term plan underpins management's base case ('Base Case'), upon which a reverse stress test has been performed. This indicates that an oil price of c.$45.0/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 $63.0/bbl for 2026 and 2027;
- 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 (the "going concern period").

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 2029. The viability assumptions are consistent with the going concern assessment, with consistent plausible downside risks applied in a Downside Case. This assessment has taken into account the Group's financial position as at 24 March 2026, its future projections; the Group's bond maturities, which occur within 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 17 to 25. 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 both the Group's Base Case and Downside 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 2029.

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.

Commodity prices
A decline in oil prices would adversely affect the Group's operations and financial condition. To mitigate oil price volatility, the Directors have hedged future production volumes utilising mainly 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.

Access to capital
Prolonged low oil prices, cost increases and production delays or outages 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 and prioritisation of debt reduction by remaining undrawn on its RBL at both 2024 and 2025 year-ends. The increase in available funds under the RBL following the recent refinancing and the long-dated maturity profile of this facility, along with the additional debt capacity expected to arise following settlement of the Magnus profit share contingent consideration provide a material level of funding within the viability period. With the Group's bonds maturing in the fourth quarter of 2027, which is within the viability period, Management have assumed, and are confident, that these will be successfully refinanced based on the Group's strong track-record and ongoing investor appetite to invest in the energy industry. Refinancing would likely occur well ahead of their maturity, providing funding beyond the viability period.

Notwithstanding the principal risks and uncertainties described 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 2029. Accordingly, the Directors therefore support this viability statement.

Oil and gas reserves and resources

EnQuest asset base as at 31 December 2025

	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 2025	123.3	52.7	**132.3**	20.0	94.2	**36.3**	143.3	146.9	**168.6**
Revisions[4]	0.5	0.3	**0.6**	2.0	30.7	**7.6**	2.6	31.0	**8.2**
Production	(10.5)	(5.2)	**(11.4)**	(2.6)	(1.7)	**(2.9)**	(13.1)	(6.9)	**(14.3)**
31 December 2025	113.3	47.8	**121.5**	19.5	123.2	**41.0**	132.8	171.0	**162.5**
2C resources (working interest)[1,2,7,8]									
1 January 2025	305.1	18.1	**308.2**	17.8	160.2	**45.4**	322.9	178.3	**353.6**
Revisions, additions and relinquishments	(0.4)	0.0	**(0.4)**	21.1	403.7	**98.9**	20.7	403.7	**98.5**
31 December 2025	304.8	18.1	**307.9**	38.9	563.9	**144.3**	343.6	582.0	**452.1**

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 newly acquired Block 12W in Vietnam
5 The above proven and probable reserves include volumes that will be consumed as fuel gas, including c.6.0 MMboe at Magnus, c.1.2 MMboe at Block 12W, c.0.6 MMboe at Kraken, c.0.1 MMboe at Golden Eagle and c.0.1 MMboe at Scolty Crathes
6 The above 2P reserves at 31 December 2025 on an entitlement basis is 152 MMboe (North Sea 122 MMboe and South East Asia 31 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 2025 include the volumes associated with the Group's PSC award at Block 12W in Vietnam and Block C in Brunei Darussalam
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 as to lead as a safe, efficient operator of mature and underinvested oil and gas assets; sustainably extending field lives and delivering superior value across the asset lifecycle, as part of a just energy 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.

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 driving top quartile operational performance, maintaining a strong balance sheet, targeting transformational growth and diversification of 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
- 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 Sustainability and Risk Committee oversees the effectiveness of the RMF and provides a forum for the Board to review selected individual risk areas in greater depth, while the Audit Committee monitors internal financial and IT-related controls.

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.

During 2025, and in preparation for reporting against the updated Provision 29 of the UK Corporate Governance Code (the 'Code') issued in January 2024, an in-depth review of the principal risks facing the Company has been undertaken. During this review, the Directors have concluded several of the principal risks are unchanged from those described in the 2024 Annual Report and Accounts. However, certain risks have been refined to more accurately capture the underlying risk while others are no longer considered principal in nature but remain part of the Group's wider risk universe and will continue to be monitored. To reach this conclusion, the Directors considered the changes in the external environment during the recent period that could threaten the Company's business model, future performance, liquidity, and reputation.

The risks that are no longer considered principal in nature are: Competition; Portfolio Concentration; International Business; JV Partners; Reputation; and Human Resources.

The Directors also considered management's view of the current risks facing the Company. Subsequently, reviews of the Group's 'Risk Library', which captures all risk areas faced by the Group into several overarching risks was undertaken. This review led to a refined risk library of 11 overarching risks (from 19 previously) which the Directors and Management believe affords appropriate focus to the key risks impacting the Group, whilst avoiding duplication. The associated 'Risk Bowties', which are used to identify risk causes and impacts, with these mapped against preventative and containment controls used to manage the risks to acceptable levels, have also been refined. These Risk Bowties remain a key element in assuring the effectiveness of the Group's material risk controls and the 11 risks are to be reviewed over a two-year period, prioritising those risks that require a new bowtie as well as retained risks that are coming up for a two-yearly review to ensure they remain fit for purpose.

The Board, 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 2025 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. An RMF Performance report is produced and reviewed at each Sustainability and Risk Committee meeting in support of this review.

Near-term and emerging risks
The Group's integrated approach to risk management 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. During the year, eight Risk Bowties were reviewed.

Ongoing geopolitical situation
The Group is monitoring the current situation in the Middle East, focusing on personal safety for its people located in the region. At the date of this report, EnQuest's people are safe and there has been no material disruption to our day -to-day activities. The Group has also 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.

Geographical diversification
The Group has successfully expanded its operational footprint in Malaysia and the wider South East Asia region following the acquisition of operations in Vietnam and the award of PSCs in Indonesia and Brunei. The Board is cognisant that this expansion creates a wider risk universe for the organisation, although such risks are mitigated by 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. At an operational level and as part of the integration processes, management reviews the control environment in place to ensure compliance and completeness, updating and/or replicating EnQuest's existing controls as necessary.

Climate change risks
While not considered an emerging risk or discrete risk in its own right, 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 Price and Foreign Exchange, Health, Safety and Environment, Access to Capital and Liquidity and Political, Regulatory and Fiscal Risk, 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.

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% continual reductions 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.

Looking ahead, EnQuest is progressing 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 Kraken flaring and emission reductions through a Bressay gas line to power Kraken operations.

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

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.

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 'Price and Foreign Exchange' risk on page 22), and/or a materially lower than expected production performance for a prolonged period (see 'Production' risk on page 20 and 'Reserves Estimation and Replacement' on page 22), 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 2025, EnQuest's Lost Time Incident frequency rate1 ('LTIF') of 0.69, represented a significant year-on-year improvement (2024: 1.55). However, the Group never finds it acceptable to incur LTIs and 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. All safety events were subject to thorough investigation and no systemic failure was identified within EnQuest systems.

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 2025, 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 (2024: Medium)

Likelihood
Medium (2024: 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 well-being of its people and assets. As a result, the potential impact and likelihood remains in line with 2024. 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 (2024: Low)

Production

RISK
The Group's production is critical to its success and is subject to a variety of risks, including: subsurface uncertainties; the complexities of 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 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 is developing plans for installing the Ninian bypass which will secure the export route for Magnus and continues to explore the potential of alternative transport options and developing hubs that may provide both risk mitigation and cost savings.

The Group added diversified growth to its production base through the accelerated delivery of gas from the Seligi 1b gas project and the acquisition of the Block 12W production assets in Vietnam and continues to consider new opportunities for expanding production having been awarded PSCs in Indonesia and Brunei during 2025.

Potential impact
High (2024: High)

Likelihood
Medium (2024: Medium)

Change from last year
There has been no material change in the potential impact or likelihood.

Risk appetite
Low (2024: Low)

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 development, 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 optimised performance and 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.

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 (2024: Medium)

Likelihood
Medium (2024: Medium)

Change from last year
The potential impact and likelihood remains unchanged, reflecting the successful accelerated delivery of the Seligi phase 1b gas project and strong progress on Heather and Broom decommissioning activities, the Ninian bypass and Bressay gas development projects going through internal stage gate reviews, and decommissioning programmes and right-sizing projects at SVT remaining in the execution phase.

Risk appetite
Medium (2024: 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.

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.

During 2025, the Group concluded the acquisition of Block 12W in Vietnam and was awarded PSCs in Indonesia and Brunei. The Vietnam acquisition added c. 7.5 MMboe of net working interest 2P reserves and c. 4.9 MMboe of net working interest 2C resources. The Block 12W PSC being extended to 2034 provides the opportunity to access upside across Block 12W. Estimated net working interest 2C resources across the DEWA (Malaysia), Indonesia and Brunei PSCs is over 100 MMboe. The Group continues actively to consider potential opportunities to acquire new production resources and development projects that meet its investment criteria.

Potential impact
High (2024: High)

Likelihood
Medium (2024: Medium)

Change from last year
There is no change to the potential impact or likelihood of this risk. The accelerated delivery of the Seligi Phase 1b project and completion of the acquisition of Block 12W in Vietnam in 2025 are balanced by other aspects, 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.

Risk appetite
Medium (2024: Medium)

Price and Foreign Exchange

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. This risk also includes the potential impacts of climate change on oil and gas supply and demand and recognises that other macroeconomic factors, such as foreign exchange and carbon pricing, could present a material risk to the business.

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 operator of mature and underinvested producing assets, the Group prioritises associated investments which deliver near-term returns and is in a position to adapt and calibrate its exposure to new investments according to developments in relevant markets. The Group monitors oil price and foreign exchange sensitivity relative to its 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 and GBP:USD foreign exchange rates within the terms of its established policy (see page 55). The Group's RBL facility also requires hedging of EnQuest's entitlement sales volumes (see page 55). To mitigate oil price volatility, the Directors have hedged a total of 5.1 MMbbls from 1 April 2026 for the next 12 months with an average floor price of $71.3/bbl and a further 3.5 MMbbls in the subsequent 12-month period with an average floor price of $64.4/bbl, in each case predominantly utilising swaps. From 1 April 2026 we have £119m hedged at an average rate of 1.3276. 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 and the cost of emissions trading allowances, with the Treasury function supporting management of foreign exchange exposure.

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

The Group's expansion into South-East Asia has targeted commodity diversification. The gas weighting of these opportunities aligns with the Group's strategic aim to reduce its overall carbon intensity.

Potential impact
High (2024: High)

Likelihood
High (2024: High)

Change from last year
The potential impact and likelihood remain high, reflecting the uncertain economic outlook, including possible impacts from forecast surplus near-term supply increases, 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 further new supply. Further, oil and gas will remain an important part of the energy mix, especially in developing regions.

Risk appetite
Medium (2024: Medium)

Access to Capital and Liquidity

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 pages 15 to 16.

APPETITE
The Group remains focused on maintaining a strong balance sheet and liquidity, controlling costs and complying with its obligations to finance providers while delivering shareholder value.

MITIGATION
EnQuest has continued to focus on optimisation of its capital structure and the maximisation of its available transactional capacity. In November 2025, EnQuest signed a six-year senior secured RBL facility totalling $800.0 million, comprising a $400.0 million secured multi-currency revolving loan facility and a $400.0 million secured multi-currency revolving letter of credit ('LoC') facility. This facility, which replaces the previous RBL, provides the Group with an enhanced capital structure that is simple, flexible and aligned with its growth ambitions. Further, during 2025, EnQuest expanded its Surety Bond provider consortium.

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 (2024: High)

Likelihood
Medium (2024: Medium)

Change from last year
There is no change to the potential impact or likelihood. The Group's successful refinancing of its RBL, expanded Letter of Credit facility, continued strong relations with its Surety Bond provider consortium and improved fiscal certainty in the UK, are balanced against a volatile

oil price environment, potential increases in the cost of emissions trading allowances and other factors such as climate change, other ESG concerns and geopolitical risks, which could impact investors' and insurers' acceptable levels of oil and gas sector exposure.

Risk appetite
Medium (2024: Medium)

Political, Regulatory and Fiscal Environment, including Climate Change risk

RISK
Unanticipated changes in the political, regulatory or fiscal environment, including those associated with climate change, 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.

The Group's exposure to country-specific risks is reduced through the Group's strategy of diversifying into new geographies, although it is recognised this does add exposure to new political, regulatory or fiscal risks.

All business development or investment activities recognise potential tax implications and the Group maintains relevant internal tax expertise, seeking external advice when appropriate.

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

Potential impact
Medium (2024: High)

Likelihood
Medium (2024: Medium)

Change from last year
There has been no material change in the potential likelihood, but the potential impact has reduced given the successor UK "windfall tax" regime to the EPL has been announced, with threshold implementation prices above many external forecasts, and no impending material regulatory changes, including those associated with climate change, known or anticipated.

EnQuest has entered into several new geographies during 2025, although many of these remain at the early stages of development which reduces the level of risk to EnQuest.

Risk appetite
Medium (2024: 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, internal communications 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 and implementing improvements as necessary has continued during 2025, with internal audit reviews planned for 2026. A number of actions were undertaken to further strengthen the Group's controls, including the following:

- Enhanced governance of IT controls across EnQuest to ensure standardised operations
- Vietnam and Malaysia cyber security assessments against EnQuest security policies conducted, with remediation for identified gaps underway
- Deployed a new security vulnerability management system which identifies technical weaknesses enabling management to assess the level of security risk and systematically reduce it

- Security strengthened through actions to improve system access rights (including relevant user groups and password updates)

Potential impact
Medium (2024: Medium)

Likelihood
High (2024: High)

Change from last year
There is no change to the impact or likelihood of this risk, although with both the threat-actor landscape and detective, preventative and containment controls continuing to evolve.

Risk appetite
Low (2024: Low)

PRODUCTION DETAILS

Average daily production on a net working interest basis	1 Jan 2025 to 31 Dec 2025 (Boepd)	1 Jan 2024 to 31 Dec 2024 (Boepd)
UK Upstream		
- Magnus	15,335	14,173
- Kraken	10,948	12,759
- Golden Eagle	2,736	3,328
- Other Upstream[1]	2,103	2,327
Total UK	**31,122**	32,587
Total Malaysia	**9,201**	8,149
Total Vietnam	**2,622**	-
Total EnQuest	**42,945**	40,736

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

KEY PERFORMANCE INDICATORS

	2025	2024	2023
Brent oil price ($/bbl)	**68.2**	80.5	82.5
ESG metrics:			
Group LTIF[1]	**0.69**	1.55	0.52
Scope 1 and Scope 2 Emissions (kilo-tonnes of CO_2 equivalent)	**1,068.0**	1,068.4	1,041.9
Business performance data:			
Production (Boepd)	**42,945**	40,736	43,812
Unit opex (production and transportation costs) ($/Boe)[2]	**25.1**	25.6	21.7
Cash expenditures ($ million)	**236.0**	313.4	211.1
Capital[2]	**179.2**	252.9	152.2
Decommissioning	**56.8**	60.5	58.9
Reported data:			
Cash generated from operations ($ million)	**497.8**	685.9	854.7
EnQuest net debt ($ million)[2]	**433.9**	385.8	480.9
Net 2P reserves (MMboe)	**163**	169	175

[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 61

Group Income Statement

For the year ended 31 December 2025

	Notes	2025 $'000	2024 $'000
Revenue and other operating income	4(a)	**1,118,300**	1,180,709
Cost of sales	4(b)	**(837,540)**	(787,383)
Gross profit/(loss)		**280,760**	393,326
Net impairment reversal/(charge) to oil and gas assets	9	**5,819**	(71,414)
General and administration expenses	4(c)	**(7,482)**	(5,702)
Other income/(expenses)	4(d)	**369,697**	(4,682)
Profit/(loss) from operations before tax and finance income/(costs)		**648,794**	311,528
Finance costs	5	**(164,591)**	(159,422)
Finance income	5	**9,224**	14,508
Profit/(loss) before tax		**493,427**	166,614
Income tax(i)	6	**(491,865)**	(72,841)
Profit/(loss) for the year attributable to owners of the parent		**1,562**	93,773
Total comprehensive profit/(loss) for the year, attributable to owners of the parent		**1,562**	93,773

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		**0.001**	0.050
Diluted		**0.001**	0.049

The attached notes 1 to 31 form part of these Group financial statements.

(i) Inclusive of a deferred tax charge of $374.7million (2024: $60.7 million) which includes a one-off non-cash impact of $123.9 million from the two-year extension to the UK Energy Profits Levy enacted in March 2025 (2024: $42.2 million from the change in Energy Profits Levy tax rate to 38% and removal of investment allowances)

Group Balance Sheet
At 31 December 2025

	Notes	**2025 $'000**	2024 $'000
ASSETS			
Non-current assets			
Property, plant and equipment	9	**2,370,131**	2,297,954
Goodwill	10	**139,510**	134,400
Intangible assets	11	**24,615**	20,563
Deferred tax assets	6(c)	**271,375**	506,481
Other receivables	15	**128,166**	2,102
Other financial assets	18	**50,818**	38,459
		2,984,615	2,999,959
Current assets			
Intangible assets	11	**1,110**	1,138
Inventories	12	**32,759**	48,976
Trade and other receivables	15	**245,469**	230,971
Current tax receivable		**2,021**	1,256
Cash and cash equivalents	13	**268,846**	280,239
Other financial assets	18	**59,491**	69
		609,696	562,649
TOTAL ASSETS		**3,594,311**	3,562,608
EQUITY AND LIABILITIES			
Equity			
Share capital and premium	19	**392,054**	392,054
Treasury shares	19	**(3,540)**	(4,425)
Share-based payments reserve	19	**12,395**	13,949
Capital redemption reserve	19	**2,006**	2,006
Retained earnings	19	**125,144**	138,882
TOTAL EQUITY		**528,059**	542,466
Non-current liabilities			
Loans and borrowings	17	**638,211**	621,440
Lease liabilities	23	**285,767**	288,262
Contingent consideration	21	**24,302**	452,891
Provisions(i)	22	**877,954**	710,976
Deferred income	24	**138,095**	138,095
Deferred tax liabilities	6(c)	**250,364**	104,698
		2,214,693	2,316,362
Current liabilities			
Loans and borrowings	17	**69,253**	43,417
Lease liabilities	23	**86,323**	46,994
Contingent consideration	21	**60,318**	20,403
Provisions(i)	22	**54,082**	55,130
Trade and other payables	16	**454,650**	414,390
Other financial liabilities	18	**10,391**	21,580
Current tax payable		**116,542**	101,866
		851,559	703,780
TOTAL LIABILITIES		**3,066,252**	3,020,142
TOTAL EQUITY AND LIABILITIES		**3,594,311**	3,562,608

(i) Decommissioning provision includes EnQuest's share of the total Block 12W decommissioning liability, noting $92.1 million has been pre-funded through an abandonment fund held in Vietnam which is disclosed within non-current other receivables

The attached notes 1 to 31 form part of these Group financial statements.

The financial statements were approved by the Board of Directors and authorised for issue on 24 March 2026 and signed on its behalf by:

Jonathan Copus
Chief Financial Officer

Group Statement of Changes in Equity

For the year ended 31 December 2025

	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 2024		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		229	–	–	(229)	–	–	–
Repurchase and cancellation of shares		(2,006)	–	(4,425)	–	2,006	(4,593)	(9,018)
Share-based payment		–	–	–	983	–	–	983
Balance at 31 December 2024		**131,508**	**260,546**	**(4,425)**	**13,949**	**2,006**	**138,882**	**542,466**
Profit for the year		**–**	**–**	**–**	**–**	**–**	**1,562**	**1,562**
Total comprehensive income for the year		**–**	**–**	**–**	**–**	**–**	**1,562**	**1,562**
Transfer of shares to Employee Benefit Trust	**19**	**–**	**–**	**885**	**(885)**	**–**	**–**	**–**
Share-based payment	**20**	**–**	**–**	**–**	**(669)**	**–**	**–**	**(669)**
Dividend paid		**–**	**–**	**–**	**–**	**–**	**(15,300)**	**(15,300)**
Balance at 31 December 2025		**131,508**	**260,546**	**(3,540)**	**12,395**	**2,006**	**125,144**	**528,059**

The attached notes 1 to 31 form part of these Group financial statements.

Group Statement of Cash Flows

For the year ended 31 December 2025

	Notes	**2025 $'000**	2024 $'000
CASH FLOW FROM OPERATING ACTIVITIES			
Cash generated from operations	29	**497,819**	685,946
Cash received/(paid) on sale/(purchase) of financial instruments		**9,075**	(10,306)
Net cash received for trading of other intangible assets		**26,829**	–
Cash paid for purchase of other intangible assets		**(6,472)**	(1,138)
Cash paid in relation to amounts previously provided for		**(481)**	(9,063)
Decommissioning spend		**(56,810)**	(60,544)
Income taxes paid		**(107,235)**	(97,264)
Net cash flows from/(used in) operating activities		**362,725**	507,631
INVESTING ACTIVITIES			
Purchase of property, plant and equipment		**(175,025)**	(249,165)
Proceeds from farm-down		**–**	1,263
Vendor financing facility repaid	18(f),24	**–**	107,518
Purchase of intangible oil and gas assets	11	**(4,225)**	(3,686)
Payment of Magnus contingent consideration – Profit share	21	**–**	(48,465)
Acquisition	30	**(20,278)**	–
Interest received		**5,286**	10,100
Net cash flows (used in)/from investing activities		**(194,242)**	(182,435)
FINANCING ACTIVITIES			
Proceeds from loans and borrowings		**152,432**	31,662
Repayment of loans and borrowings		**(146,451)**	(162,304)
Payment for repurchase of shares		**–**	(9,018)
Payment of obligations under financing leases	23	**(83,061)**	(130,065)
Dividend paid	8	**(15,300)**	–
Interest paid		**(96,997)**	(83,162)
Other finance expenses paid		**(3,606)**	–
Net cash flows (used in)/from financing activities		**(192,983)**	(352,887)
NET (DECREASE)/INCREASE IN CASH AND CASH EQUIVALENTS		**(24,500)**	(27,691)
Net foreign exchange on cash and cash equivalents		**13,107**	(5,642)
Cash and cash equivalents at 1 January		**280,239**	313,572
CASH AND CASH EQUIVALENTS AT 31 DECEMBER		**268,846**	280,239
Reconciliation of cash and cash equivalents			
Total cash at bank and in hand	13	**265,886**	226,317
Restricted cash	13	**2,960**	53,922
Cash and cash equivalents per balance sheet		**268,846**	280,239

The attached notes 1 to 31 form part of these Group financial statements.

Notes to the Group Financial Statements

For the year ended 31 December 2025

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 2025 were authorised for issue in accordance with a resolution of the Board of Directors on 24 March 2026.

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 2025 and 2024 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 2025 and 2024 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 24 March 2026 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 2025.

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 which impact upon IFRS measures or, by defining new measures. See the Glossary – Non-GAAP Measures on page 61 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.

During 2025, EnQuest has continued to focus on optimisation of its capital structure and the maximisation of its available transactional capacity.

In November, EnQuest signed a new six-year senior secured reserves-based lending facility which replaced the previous RBL, providing the Group with an enhanced capital structure that is simple, flexible and aligned with its growth ambitions. Details of the amended facility are provided in note 17. In February 2026, the Group made final settlement for the Magnus profit share contingent consideration, securing 100% of future Magnus cash flows while maintaining its limited exposure to future decommissioning expenditure at the asset. This credit-enhancing settlement, simplifies the Group's balance sheet, unlocks the full upside of one of EnQuest's core assets, and further secures longer term capacity under its RBL.

EnQuest closely monitors and manages its funding position and liquidity requirements throughout the year, including forecast covenant results. Cash forecasts are regularly produced and discussed, with 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. Management have considered the impact of the situation in the Middle East, particularly on future oil prices. Reflecting the uncertainty as to how long the conflict and the period of elevated oil prices will last, management have assumed in the base case that the average oil price for the going concern period will be $70.0/bbl. Although this is slightly higher than that used in its impairment assessment (see note 2) to reflect post year-end pricing trends, it is considerably below current spot prices.

The Group's latest approved budget and long term plan underpins management's base case ('Base Case'), upon which a reverse stress test has been performed. This indicates that an oil price of c.$45.0/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 $63.0/bbl for 2026 and 2027;
- 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 (the "going concern period").

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:

- Lack of Exchangeability (Amendments to IAS 21)

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 and disclosure in financial statements*
IFRS 19	*Subsidiaries without Public Accountability: Disclosures*

Other than IFRS18, 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, which is for periods commencing on or after 1 January 2027.

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 2025, 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 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 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 Price and Foreign Exchange Risk 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 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 or impairment reversal 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 2025 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 half-year and, in 2025, the post-tax discount rate was estimated at 9.0% (2024: 10.0%) 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 2025. 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 2024, 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. Discounts or premiums are applied to price assumptions based on the characteristics of the oil produced and the terms of the relevant sales contracts.

When compared to the latest available Paris-consistent climate scenario modelling data released by the World Business Council of Sustainable Development ('WBCSD') in May 2024, EnQuest's assumption is broadly aligned with the top end of a range of Paris-consistent scenario's. When compared to the International Energy Agency's ('IEA') forecast prices under its Net Zero Emissions by 2050 Scenario ('NZE') ,published in November 2025, which is also considered a Paris-consistent scenario and maps out a pragmatic but ambitious global pathway for the energy sector to achieve net zero $CO2$ emissions by 2050 and is consistent with a long-term goal of limiting the rise in global average temperatures to 1.5 °C (with a 50% probability), EnQuest's short-term assumptions are below those assumed under the NZE, while its medium and longer-term prices are significantly higher. As further considered later in this note, management believes a 10% reduction in crude oil price assumptions to be a reasonably possible change and has provided an impairment sensitivity on this basis. However, the potential impact of applying the IEA NZE Scenario, which is just one view of the possible impact of climate change, would result in a materially higher impairment charge. An inflation rate of 2% (2024: 2%) is applied from 2030 onwards to determine the price assumptions in nominal terms (see table below).

The price assumptions used in 2024 were $75.0/bbl (2025), $75.0/bbl (2026), $75.0/bbl (2027) and $76.5/bbl real thereafter, inflated at 2.0% per annum from 2028.

	2026	2027	2028	2029>
Brent oil ($/bbl)	65.0	67.5	72.5	75.0

- Inflated at 2% from 2030

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, 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 17) 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 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 $198.7 million, which is approximately 8% of the net book value of property, plant and equipment as at 31 December 2025.

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 9.0% 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 2025 would have been approximately $51.9 million higher. If the discount rate was one percentage point lower, the net impairment reversal would have been approximately $24.3 million higher.

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 $139.5 million on its balance sheet (2024: $134.4 million), principally relating to the acquisitions of the Magnus oil field (acquired in 2018) in the UK and Block 12W in Vietnam (acquired in 2025). 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
Judgement: During 2025, management commenced discussions with bp to settle the 75% Magnus contingent consideration arrangement. Management assessed that the agreement to settle the Magnus contingent consideration, signed and concluded in February 2026, was substantially agreed with bp at 31 December 2025. Therefore the agreement price of $60.0 million was deemed to be a reasonable fair value in line with IFRS 13, for the contingent consideration as at 31 December 2025, resulting in a pre-tax gain of $391.3 million. If management had concluded the agreement was not substantially complete at year end, the contingent consideration would have continued to be valued based on the present value of the future expected cash flows from the Magnus field, which at 30 June 2025 resulted in a provision of $432.9 million being recorded**.**

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 Group assesses discount rates in each geography in which it operates using an appropriate benchmark, usually government bonds. As such, the nominal discount rate used to determine the balance sheet obligations ranged from 3.1% to 4.5% (2024: 3.1% to 4.5%). Costs at future prices are determined by applying inflation rates. The inflation rates applied are usually managements estimate based on relevant in-country benchmarking, but in certain circumstances inflation is applied in accordance with the relevant operating agreement. As such, where inflation has been applied to decommissioning costs, it has ranged between 1.0% and 2.0% per annum thereafter (2024: 1.0% to 2.0%). The weighted average period over which North Sea decommissioning costs are generally expected to be incurred is estimated to be approximately 12 years.

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 sensitivity has only been run for the UK North Sea segment given its materiality compared to Malaysia and Vietnam. 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 $58.6 million (2024: $59.4 million). The pre-tax impact on the Group income statement would be a charge of approximately $57.5 million (2024: $58.7 million).

Business combination
Judgement: The Group determined that the acquisition of Block 12W in Vietnam during the year was the acquisition of a business, due to the acquired set of activities and assets including inputs and processes critical to the ability to continue producing outputs.

Estimates: While the risk that the acquisition fair value of Block 12W in Vietnam materially changes in the next 12 months is low and so is not considered a key source of estimation uncertainty, for business combinations the Group determines the fair value of property, plant and equipment acquired based on the discounted cash flows at the time of acquisition from the proven and probable reserves. In assessing the discounted cash flows, the estimated future cash flows attributable to the asset are discounted to their present value using a discount rate that reflects the market assessments of the time value of money and the risks specific to the asset at the time of the acquisition. In calculating the asset fair value, the Group will apply oil price assumptions representing management's view of the long-term oil price.

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 2025, the Group had two significant operating segments: the North Sea and Malaysia. The Vietnam, Indonesia and Brunei operations, which are new for 2025, are not yet deemed significant in accordance with the quantitative thresholds for separate disclosure under IFRS 8, and so these operations have been aggregated into one reporting group, alongside other Corporate activities. Operations are managed by location and all information is presented per geographical segment. The Group's segmental reporting structure remained in place throughout 2025. 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 2025 $'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	**895,313**	**114,110**	**52,842**	**1,062,265**	**–**	**1,062,265**
Other operating income/(expense)	**1,770**	**–**	**343**	**2,113**	**53,922**	**56,035**
Total revenue and other operating income/(expense)	**897,083**	**114,110**	**53,185**	**1,064,378**	**53,922**	**1,118,300**
Income/(expenses) line items:						
Depreciation and depletion	**(244,937)**	**(18,183)**	**(9,308)**	**(272,428)**	**–**	**(272,428)**
Net impairment reversal/(charge) to oil and gas assets	**5,819**	**–**	**–**	**5,819**	**–**	**5,819**
Exploration write-off and impairments	**(173)**	**–**	**–**	**(173)**	**–**	**(173)**
Segment profit/(loss)(ii), (iii)	**489,959**	**43,770**	**9,090**	**542,819**	**105,975**	**648,794**
Other disclosures:						
Capital expenditure(iv)	**148,814**	**63,214**	**1,328**	**213,356**	**–**	**213,356**

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

(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) The consolidated profit/(loss) figure reconciles with Profit/(loss) from operations before tax and finance income/(costs) in the income statement. 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 2025 $'000	Year ended 31 December 2024 $'000
Segment profit/(loss) before tax and finance income/(costs)	**542,819**	328,903
Finance costs	**(164,591)**	(159,422)
Finance income	**9,224**	14,508

Gain/(loss) on derivatives[i]	**105,975**	(17,375)
Profit/(loss) before tax	**493,427**	166,614

(i) Includes $28.5 million realised gains on derivatives (2024: $17.6 million realised losses) and $77.5 million unrealised gains on derivatives (2024: $0.3 million). See note 18(b) for further detail

Revenue from three customers each exceeds 10% of the Group's consolidated revenue arising from sales of crude oil, with amounts of $414.3 million, $103.6 million and $93.0 million per each single customer (2024: three customers; $394.8 million, $156.0 million, and $115.7 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 2025 $'000	Year ended 31 December 2024 $'000
Revenue from contracts with customers:		
Revenue from crude oil sales	**858,166**	1,020,266
Revenue from gas and condensate sales[i]	**200,526**	164,647
Tariff revenue	**3,573**	2,644
Total revenue from contracts with customers	**1,062,265**	1,187,557
Realised gains/(losses) on commodity derivative contracts (see note 18)	**8,744**	(12,907)
Unrealised gains/(losses) on commodity derivative contracts (see note 18)	**45,178**	3,090
Other	**2,113**	2,969
Total revenue and other operating income	**1,118,300**	1,180,709

(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 2025 $'000				Year ended 31 December 2024 $'000			
	North Sea	**Malaysia**	**Vietnam**	**Total**	North Sea	Malaysia	Vietnam	Total
Revenue from contracts with customers:								
Revenue from crude oil sales	**703,071**	**103,299**	**51,796**	**858,166**	900,310	119,956	–	1,020,266
Revenue from gas and condensate sales[i]	**192,074**	**7,406**	**1,046**	**200,526**	162,951	1,696	–	164,647
Tariff revenue	**168**	**3,405**	**–**	**3,573**	568	2,076	–	2,644
Total revenue from contracts with customers	**895,313**	**114,110**	**52,842**	**1,062,265**	1,063,829	123,728	–	1,187,557

(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 2025 $'000	Year ended 31 December 2024 $'000
Production costs	**344,580**	307,634
Tariff and transportation expenses	**69,189**	70,449
Realised (gain)/loss on derivative contracts related to operating costs (see note 18)	**(19,711)**	4,735
Unrealised (gains)/losses on derivative contracts related to operating costs (see note 18)	**(32,342)**	2,823
Other non-cash UKA losses	**11,490**	1,335
Change in lifting position	**3,350**	3,528
Crude oil inventory movement	**14,057**	(1,356)
Depletion of oil and gas assets(i)	**267,299**	263,251
Other cost of operations(ii)	**179,628**	134,984
Total cost of sales	**837,540**	787,383

(i) Includes $29.2 million (2024: $27.9 million) Kraken and Vietnam FPSO right-of-use asset depreciation charge and $26.3 million (2024: $23.5 million) of other right-of-use assets depreciation charge
(ii) Includes $166.2 million (2024: $125.7 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 2025 $'000	Year ended 31 December 2024 $'000
Staff costs (see note 4(e))	**73,634**	75,833
Depreciation(i)	**5,129**	6,040
Other general and administration costs	**26,359**	26,748
Recharge of costs to operations and joint venture partners	**(97,640)**	(102,919)
Total general and administration expenses	**7,482**	5,702

(i) Includes $3.7 million (2024: $3.4 million) right-of-use assets depreciation charge on buildings

(d) Other income/(expenses)

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Net foreign exchange (losses)/gains	**(28,330)**	9,975
Rental income from office sublease	**1,893**	2,201
Fair value changes in contingent consideration (see note 21)	**387,145**	(15,904)
Change in decommissioning provisions (see note 22)	**(9,727)**	(6,666)
Change in Thistle decommissioning provision (see note 22)	**(4,772)**	(412)
Drilling rig contract cancellation costs(i)	–	(14,629)
Write-down of relinquished assets/unsuccessful exploration expenditure (see note 11)	**(173)**	(183)
Insurance income	**(53)**	1,663
Reversal of provisions	**4,685**	–
Other	**19,029**	19,273
Total other income/(expenses)	**369,697**	(4,682)

(i) In 2024, 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 2025 $'000	Year ended 31 December 2024 $'000
Wages and salaries	**62,286**	66,700
Social security costs	**6,202**	5,899
Defined contribution pension costs	**5,932**	5,265
(Credit)/expense of share-based payments (see note 20)	**(669)**	983
Other staff costs	**13,969**	12,300
Total employee costs	**87,720**	91,147
Contractor costs	**46,529**	37,493

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Total staff costs	**134,249**	128,640
General and administration staff costs (see note 4(c))	**73,634**	75,833
Non-general and administration costs	**60,615**	52,807
Total staff costs	**134,249**	128,640

The monthly average number of persons, excluding contractors, employed by the Group during the year was 694, with 359 in the general and administration staff costs and 335 directly attributable to assets (2024: 673 of which 336 in general and administration and 337 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 2025 and for the comparative year ended 31 December 2024 were payable by the Group to Deloitte:

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Fees payable to the Company's auditor for the audit of the parent company and Group financial statements	**1,476**	1,367
The audit of the Company's subsidiaries	**303**	173
Total audit	**1,779**	1,540
Audit-related assurance services(i)	**694**	589
Total audit and audit-related assurance services	**2,473**	2,129
Total auditor's remuneration	**2,473**	2,129

(i) Audit-related assurance services in both years primarily include the review of the Group's interim results, G&A assurance review and the provision of customary comfort letters in respect of the Group's refinancing activities. Included within 2025 is £30,000 (2024: nil) related to other services that are not assurance related

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 2025 $'000	Year ended 31 December 2024 $'000
Finance costs:		
Loan interest payable	**6,027**	18,524
Bond interest payable	**69,269**	54,971
Unwinding of discount on decommissioning provisions (see note 22)	**35,912**	30,290
Unwinding of discount on other provisions (see note 22)	**755**	911
Debt refinancing fees (see note 17)	**–**	4,809
Finance charges payable under leases (see note 23)	**25,100**	27,673
Finance fees on loans and bonds including amortisation of capitalised fees	**15,337**	14,473
Other financial expenses	**12,191**	7,771
Total finance costs	**164,591**	159,422
Finance income:		
Bank interest receivable	**6,535**	11,110
RockRose loan interest (see note 18(f))	**2,639**	3,263
Other financial income	**50**	135
Total finance income	**9,224**	14,508

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.

The Group has applied the mandatory exception to recognising and disclosing information about the deferred tax assets and liabilities relating 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.

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 2030. 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 2025 $'000	Year ended 31 December 2024 $'000
Current UK income tax		
Current income tax charge	**1,051**	–
Current overseas income tax		
Current income tax charge	**12,351**	11,432
Adjustments in respect of current income tax of previous years	**307**	(746)
UK Energy Profits Levy		
Current year charge	**84,069**	10,262
Adjustments in respect of current charge of previous years(i)	**19,378**	(8,803)
Total current income tax	**117,156**	12,145
Deferred UK income tax		
Relating to origination and reversal of temporary differences	**222,897**	42,745
Adjustments in respect of deferred income tax of previous years(i)	**12,209**	(9,103)
Deferred overseas income tax		
Relating to origination and reversal of temporary differences	**7,581**	7,071
Adjustments in respect of deferred income tax of previous years	**(363)**	31
Deferred UK Energy Profits Levy		
Relating to origination and reversal of temporary differences	**134,985**	11,156
Adjustments in respect of changes in tax rates	**–**	6,889
Adjustments in respect of deferred charge of previous years	**(2,600)**	1,907
Total deferred income tax	**374,709**	60,696
Income tax expense reported in profit or loss	**491,865**	72,841

(i) Adjustments in respect of previous years arose upon finalisation of various UK tax returns and include an additional EPL current tax liability of $19.4 million and an additional deferred tax liability of $7.8 million. These adjustments reflect corrections to the amount of tax relief accrued in the 2024 financial year end group tax position arising as a result of reclassifications made during that year from inventory to property, plant and equipment as part of a review of well supplies

(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 2025 $'000	Year ended 31 December 2024 $'000
Profit/(loss) before tax	**493,427**	166,614

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
UK statutory tax rate applying to North Sea oil and gas activities of 40% (2024: 40%)	**197,371**	66,646
Supplementary corporation tax non-deductible expenditure	**4,383**	5,809
Non-deductible expenditure[(i)]	**8,537**	26,114
Non-taxable gain on sale of assets	**–**	505
Petroleum revenue tax (net of income tax benefit)	**(363)**	(8,938)
Tax in respect of non-ring-fence trade	**13,776**	7,298
Deferred tax asset not recognised in respect of non-ring-fence trade	**21,426**	12,243
Deferred tax asset recognised on previously unrecognised losses	**–**	(48,115)
UK Energy Profits Levy[(ii)]	**95,179**	(13,921)
UK Energy Profits Levy – changes in tax rates[(iii)]	**–**	6,889
UK Energy Profits Levy – abolishment of Investment Allowance[(iii)]	**–**	35,339
UK Energy Profits Levy – extension to March 2030[(iv)]	**123,875**	–
Adjustments in respect of prior years	**28,931**	(16,713)
Overseas tax rate differences	**(1,323)**	2,045
Share-based payments	**(132)**	(1,407)
Other differences	**205**	(953)
At the effective income tax rate of 100% (2024: 44%)	**491,865**	72,841

(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) This consists of an Energy Profits Levy current tax charge of $84.1 million (2024: $10.3 million) and deferred Energy Profits Levy charge of $11.1 million (2024: $18.0 million).The 2025 charge was impacted by the higher rate of 38% which applied from 1 November 2024 (period to 31 October 2024: 35%) and the removal of investment allowances

(iii) Refers to the impact of the increased rate and removal of investment allowances that were substantially enacted in 2024

(iv) Reflects the impact of the substantively enacted two-year extension referred to in part (e) below

(c) Deferred income tax

Deferred income tax relates to the following:

	Group balance sheet		Charge/(credit) for the year recognised in profit or loss	
	2025 $'000	2024 $'000	**2025 $'000**	2024 $'000
Deferred tax liability				
Accelerated capital allowances	**1,039,396**	911,501	**126,945**	33,701
	1,039,396	911,501		
Deferred tax asset				
Losses	**(627,124)**	(717,900)	**90,777**	(22,012)
Decommissioning liability	**(296,069)**	(263,705)	**(33,047)**	2,095
Other temporary differences[(i)]	**(137,214)**	(331,679)	**190,034**	46,912
	(1,060,407)	(1,313,284)	**374,709**	60,696
Net deferred tax (assets)[(ii)]	**(21,011)**	(401,783)		
Reflected in the balance sheet as follows:				
Deferred tax assets	**(271,375)**	(506,481)		
Deferred tax liabilities	**250,364**	104,698		
Net deferred tax (assets)	**(21,011)**	(401,783)		

(i) Predominantly includes $107.7 million on deferred income in note 24 and $17.5 million Petroleum Revenue Tax refunds

(ii)The total amounts for EPL included in net deferred assets are $276.3 million for accelerated capital allowances offset by $56.7 million for other items, which predominantly includes $52.5 million related to deferred income (note 24)

Reconciliation of net deferred tax assets/(liabilities)

	2025 $'000	2024 $'000
At 1 January	**401,783**	462,479
Tax expense during the period recognised in profit or loss	**(374,709)**	(60,696)
Deferred taxes acquired in business combinations (see note 30)	**(6,063)**	–
At 31 December	**21,011**	401,783

(d) Tax losses

The Group's deferred tax assets at 31 December 2025 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). The Group is currently recognising all UK tax losses (with the exception of those noted below) and neither a 10% increase or 10% decrease in oil price would result in any change to the full recognition.

The Group has unused UK mainstream corporation tax losses of $578.4 million (2024: $496.1 million) and ring-fence tax losses of $1,117.5 million (2024: $1,117.5 million) associated with EnQuest Progress Limited, for which no deferred tax asset has been recognised at the balance sheet date as 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 $4.2 million (2024: $6.3 million) remaining unrecognised.

The Group has unused Malaysian income tax losses of $16.3 million (2024: $14.7 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
On 29 July 2024, the UK Government announced various changes to the EPL including an extension to 31 March 2030 (previously 31 March 2028) to which the EPL applies. This extension was substantively enacted on 3 March 2025, with the impact on the current period financial statements tax charge and deferred tax for EPL being $123.9 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.

At 31 December 2025, the Group held 20,000,000 Ordinary shares (2024: 25,000,000 Ordinary shares) which were classified in the balance sheet as Treasury shares. The Treasury shares have been excluded for the purposes of calculating the basic and diluted earnings per share at 31 December 2025.

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**	
	2025 $'000	2024 $'000	**2025 million**	2024 million	**2025 $**	2024 $
Basic	**1,562**	93,773	**1,859.9**	1,891.9	**0.001**	0.050
Dilutive potential of Ordinary shares granted under share-based incentive schemes	**–**	–	**24.2**	24.3	**–**	(0.001)
Diluted	**1,562**	93,773	**1,884.1**	1,916.2	**0.001**	0.049

8. Distributions paid and proposed
The Company paid dividends of 0.616 pence per share during the year ended 31 December 2025 (2024: none).

Following the successful implementation of its capital discipline strategy, EnQuest remains committed to delivering sustainable shareholder returns. Building on the inaugural dividend paid last year, the Board is pleased to propose a second final ordinary dividend of 0.801 pence per share (equivalent to approximately $20.0 million). This proposed dividend is subject to approval by shareholders at the Annual General Meeting scheduled for 22 May 2026, and accordingly has not been recognised as a liability as at 31 December 2025. If approved, the dividend will be paid on 5 June 2026 to shareholders on the register at 8 May 2026, with shares trading ex-dividend from 7 May 2026.

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 and Vietnam FPSOs which are 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 2024	**9,243,807**	**68,578**	**904,994**	**10,217,379**
Additions	325,813	394	16,453	342,660
Change in decommissioning provision	(741)	–	–	(741)
At 1 January 2025	**9,568,879**	**68,972**	**921,447**	**10,559,298**
Additions	**176,552**	**277**	**32,302**	**209,131**
Acquisition (see note 30)	**24,716**	**–**	**33,002**	**57,718**
Disposals	**(1,672)**	**–**	**(37,881)**	**(39,553)**
Change in decommissioning provision (note 22)	**77,862**	**–**	**–**	**77,862**
At 31 December 2025	**9,846,337**	**69,249**	**948,870**	**10,864,456**
Accumulated depreciation, depletion and impairment:				
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 1 January 2025	**7,651,364**	**61,997**	**547,983**	**8,261,344**
Charge for the year	**211,616**	**1,628**	**59,184**	**272,428**
Net impairment (reversal)/charge for the year	**23,019**	**–**	**(28,838)**	**(5,819)**
Disposal	**–**	**–**	**(33,628)**	**(33,628)**
At 31 December 2025	**7,885,999**	**63,625**	**544,701**	**8,494,325**
Net carrying amount:				
At 31 December 2025	**1,960,338**	**5,624**	**404,169**	**2,370,131**
At 31 December 2024	1,917,515	6,975	373,464	2,297,954
At 1 January 2024	1,879,744	9,264	407,732	2,296,740

The amount of borrowing costs capitalised during the year ended 31 December 2025 was nil (2024: 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 reversal/(charge)		Recoverable amount(i)	
	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000	**31 December 2025 $'000**	31 December 2024 $'000
North Sea	**5,819**	(71,414)	**1,100,312**	1,172,487
Net pre-tax impairment reversal/(charge)	**5,819**	(71,414)		

(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 2025 net impairment reversal of $5.8 million relates to producing assets in the UK North Sea (an impairment reversal of $94.3 million at Kraken offset by charges of $33.5 million for GKA and Scolty/Crathes CGU, $43.5 million for Golden Eagle and $11.5 million for Alba). Impairment reversals/charges were primarily driven by a combination of lower discount rate, changes in production and cost profiles, including the impact of weaker USD, and lower near-term oil price assumptions.

The 2024 net impairment charge of $71.4 million related 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.

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:

	2025 **$'000**	2024 $'000
Cost and net carrying amount		
At 1 January	**134,400**	134,400
Acquisition (see note 30)	**5,110**	–
At 31 December	**139,510**	134,400

The majority of the goodwill relates to the 75% acquisition of the Magnus oil field and associated interests. The remaining opening balance relates to the acquisition of the GKA and Scolty Crathes fields. During 2025, the Group acquired Block 12W in Vietnam (see note 30) resulting in goodwill recognised of $5.1 million.

Impairment testing of goodwill

Goodwill, which has been acquired through business combinations, has been allocated as appropriate to the UK North Sea segment grouping of CGUs and the Vietnam CGU, and these are 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), while the Vietnam CGU relates to the Block 12W asset.

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 2025 (2024: nil) based on a fair value less costs to dispose valuation of the 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 reasonably possible change for the purposes of sensitivity analysis (see note 2). A 10% reduction in oil price would result in an impairment charge of $70.7 million (2024: 10% reduction would result in an impairment charge of $66.7 million). A 15% reduction in oil price would fully impair goodwill (2024: 17%), however Management do not consider this to be a reasonably possible change.

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 2025, there was no impairment of historical exploration and appraisal expenditures (2024: nil).

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 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 1 January 2025	**129,716**	**1,138**	**130,854**
Additions	**4,225**	**6,472**	**10,697**
Write-off of relinquished licence	**(173)**	**–**	**(173)**
Disposal	**–**	**(6,500)**	**(6,500)**
At 31 December 2025	**133,768**	**1,110**	**134,878**
Accumulated impairment:			
At 1 January 2024, 1 January 2025 and 31 December 2025	**(109,153)**	**–**	**(109,153)**
Net carrying amount:			
At 31 December 2025	**24,615**	**1,110**	**25,725**
At 31 December 2024	20,563	1,138	21,701
At 1 January 2024	18,323	876	19,199

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.

	2025 $'000	2024 $'000
Hydrocarbon inventories	**8,487**	22,544
Well supplies	**24,272**	26,432
	32,759	48,976

During 2025, a net charge of $16.9 million was recognised within cost of sales in the Group income statement relating to inventory, reflecting additional sales related to Magnus hydrocarbon stock (2024: net gain of $6.9 million).

The inventory valuation at 31 December 2025 is stated net of a provision of $22.5 million (2024: $28.5 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.

	2025 $'000	2024 $'000
Available cash	**265,886**	226,317
Restricted cash	**2,960**	53,922
Cash and cash equivalents	**268,846**	280,239

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

Restricted cash at 31 December 2025 includes a residual $1.2 million in accounts relating to 2025 decommissioning security agreement obligations (31 December 2024: $53.4 million). The remaining $1.8 million of restricted cash relates to a Performance Bond in Indonesia (31 December 2024: $0.5 million related to bank guarantees for the Group's Malaysian assets).

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 2025	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						
Commodity contracts	18(a)	**36,754**	**36,754**	**–**	**36,754**	**–**
Forward foreign currency contracts	18(a)	**932**	**932**	**–**	**932**	**–**
Forward UKA contracts	18(a)	**28,721**	**28,721**	**–**	**28,721**	**–**
Other financial assets measured at FVPL						**–**
Quoted equity shares		**6**	**6**	**6**	**–**	**–**
Total financial assets measured at fair value		**66,413**	**66,413**	**6**	**66,407**	**–**

31 December 2025	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 amortised cost:						
Vendor financing facility	18(f)	43,896	43,896	–	43,896	–
Total financial assets measured at amortised cost[i]		43,896	43,896	–	43,896	–
Liabilities measured at fair value:						
Derivative financial liabilities measured at FVPL						
Commodity contracts	18(a)	1,997	1,997	–	1,997	–
Forward UKA contracts	18(a)	8,394	8,394	–	8,394	–
Other financial liabilities measured at FVPL						
Contingent consideration	21	84,620	84,620	–	–	84,620
Total liabilities measured at fair value		95,011	95,011	–	10,391	84,620
Liabilities measured at amortised cost						
Interest-bearing loans and borrowings[i]	17	60,324	60,324	–	60,324	–
GBP retail bond 9.00%[ii]	17	181,812	180,892	180,892	–	–
USD high yield bond 11.625%[ii]	17	465,328	470,878	470,878	–	–
Total liabilities measured at amortised cost[iii]		707,464	712,094	651,770	60,324	–

(i) Amortised cost is a reasonable approximation of the fair value, carrying value includes accrued interest

(ii) Carrying value includes accrued interest and related fees

(iii) Amounts included in the Total column, exclude related fees

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	–
GBP retail bond 9.00%[ii]	17	169,371	161,461	161,461	–	–
USD 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, carrying value includes accrued interest

(ii) Carrying value includes accrued interest and related fees

(iii) Amounts included in the Total column, exclude 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 (2024: 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 2). A reconciliation of movements is disclosed in note 29.

15. Trade and other receivables

	2025 $'000	2024 $'000
Current		
Trade receivables	**15,357**	20,151
Joint venture receivables	**104,608**	106,963
Under-lift position	**18,073**	16,806
VAT receivable	**12,377**	7,574
Vietnam lease receivable from joint venture partners	**5,122**	–
Other receivables[(i)]	**55,015**	25,989
Prepayments	**13,821**	5,720
Accrued income	**21,096**	47,768
Total current	**245,469**	230,971
Non-current		
Vietnam abandonment fund	**92,079**	–
Vietnam lease receivable from joint venture partners	**19,473**	–
Other receivables	**16,614**	2,102
Total non-current	**128,166**	2,102

(i) Predominantly relates to amounts charged to SVT owners and users

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 2025 or 2024.

Non-current receivables mainly comprise the Group's share of cash contributions made into an abandonment fund which was established to ensure that sufficient funds exist to meet future abandonment obligations on Block 12W in Vietnam. The funds are maintained in a bank account by PetroVietnam and the joint venture partners retain the legal rights and obligations to all monies contributed to the abandonment funds, pending commencement of abandonment operations.

The lease receivable relates to the Group's lease of an FPSO used on Block 12W in Vietnam. The related liability is recorded on a gross basis as EnQuest is the sole signatory to the lease, with joint venture partners providing a parent company guarantee with respect to their share of the lease liability. The Group's share of this liability is recorded as a right of use asset (see note 23) with the remainder, representing the share of future payments to be reimbursed by the other partners in Block 12W in Vietnam, recorded as an "other receivable" split between current and non-current based on the expected timing of reimbursement by the partners.

Other non-current receivables represents capitalised fees associated with the Group's Reserve Based Lending Facility disclosed within trade and other receivables to better reflect the variable nature of drawings under the facility.

16. Trade and other payables

	2025 $'000	2024 $'000
Current		
Trade payables	**124,806**	138,822
Accrued expenses	**287,408**	209,225
Over-lift position	**8,136**	16,849
Joint venture creditors	**25,750**	46,187
Other payables	**8,550**	3,307
Total current	**454,650**	414,390

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 ten and 30 days.

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

17. Loans and borrowings

	2025 $'000	2024 $'000
Loans	**60,324**	33,972
Bonds	**647,140**	630,885
	707,464	664,857

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

	2025			2024		
	Principal $'000	**Fees $'000**	**Total $'000**	Principal $'000	Fees $'000	Total $'000
SVT working capital facility	**36,331**	**–**	**36,331**	33,972	–	33,972
Vendor loan facility	**22,096**	**–**	**22,096**	–	–	–
USD high yield bond 11.625%	**465,000**	**(6,156)**	**458,844**	465,000	(10,661)	454,339
GBP retail bond 9.00% (GBP 133.3 million)	**179,367**	**–**	**179,367**	167,101	–	167,101
Accrued interest(i)	**10,826**	**–**	**10,826**	9,445	–	9,445
Total borrowings	**713,620**	**(6,156)**	**707,464**	675,518	(10,661)	664,857
Due within one year			**69,253**			43,417
Due after more than one year			**638,211**			621,440
Total borrowings			**707,464**			664,857

(i) Accrued interest includes vendor loan facility interest accruals of $1.9 million (2024: $nil) and bond interest accruals of $8.9 million (2024: $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 November 2025, the Group agreed a new six-year Senior Secured Reserves Based Lending ('RBL') facility totalling $800.0 million comprising a $400.0 million multi-currency revolving loan facility, $400.0 million multi-currency revolving letter of credit facility and an accordion of up to $800.0 million which, although uncommitted, provides the potential to extend the secured revolving loan facility and the revolving letter of credit facility by up to $400.0 million each. The maturity of the facility is December 2031. Funds can only be drawn under the loan facility to a maximum amount of the lesser of: (i) the total commitments; and (ii) the borrowing base amount. Interest accrues at 4.00%, plus a combination of an agreed credit adjustment spread and the Secured Overnight Financing Rate ('SOFR'). The facility replaced the Group's previous reserves based lending facility, which was signed in October 2022 and accrued interest at 4.50%, plus a combination of an agreed credit adjustment spread and the SOFR.

Fees associated with the new RBL of $20.4 million were capitalised within trade and other receivables (note 15) and are being amortised over the period of the facility on a straight-line basis. The remaining unamortised fees relating to the previous RBL of $2.4 million were expensed within finance costs.

At 31 December 2025, there were no loan drawdowns under the RBL (2024: $nil), with $400.0 million remaining available for drawdown (2024: $176.4 million). At 31 December 2025, Letter of Credit utilisation was $381.5 million (2024: $54.1 million). The increased utilisation of Letters of Credit reflected their use in providing security under the Group's decommissioning security obligations, replacing the Group's prior period's use of surety bonds and cash.

SVT working capital facility
In 2024, EnQuest 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 based on certain qualifying invoices that EnQuest has paid up to an amount of £23.7 million, with interest payable monthly at a rate of 9.50% per annum. At 31 December 2025, $22.1 million had been drawn down on the facility (2024: $nil).

US Dollar 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.

The above carrying value of the bond as at 31 December 2025 is $458.8 million (2024: $454.3 million). This includes bond principal of $465.0 million (2024: $465.0 million) and unamortised issue premium on the tap of $1.0 million (2024: $1.4 million) less the unamortised original issue discount of $1.5 million (2024: $2.4 million) and unamortised fees of $5.8 million (2024: $9.7 million). The fair value of the US Dollar high yield bond is disclosed in note 14.

GBP retail bond 9.00%
On 27 April 2022, the Group issued a new 9.00% GBP retail bond following a successful partial exchange and cash offer. The principal of the GBP 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 2025 is $179.4 million (2024: $167.1 million). All fees associated with this offer were recognised in the income statement in 2022. The fair value of the GBP retail bond 9.00% is disclosed in note 14.

18. Other financial assets and financial liabilities
(a) Summary as at year end

	2025		2024	
	Assets $'000	**Liabilities $'000**	Assets $'000	Liabilities $'000
Fair value through profit or loss:				
Derivative commodity contracts	**35,009**	**1,997**	69	10,497
Forward foreign currency contracts	**932**	**–**	–	2,354
Derivative UKA contracts	**23,550**	**8,394**	–	8,729
Total current	**59,491**	**10,391**	69	21,580
Fair value through profit or loss:				
Derivative commodity contracts	**1,745**	**–**	–	–
Derivative UKA contracts	**5,171**	**–**	–	–
Quoted equity shares	**6**	**–**	6	–
Amortised cost:				
Other receivables (Vendor financing facility) (notes 18(f), 24)	**43,896**	**–**	38,453	–
Total non-current	**50,818**	**–**	38,459	–
Total other financial assets and liabilities	**110,309**	**10,391**	38,528	21,580

(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 2025	**Realised $'000**	**Unrealised $'000**	**Realised $'000**	**Unrealised $'000**
Commodity options	**(6,561)**	**7,766**	**–**	**–**
Commodity swaps	**15,567**	**37,225**	–	**–**
Commodity futures	**(262)**	**187**	–	**–**
Foreign exchange contracts	**–**	**–**	**20,766**	**3,286**
UKA contracts	–	**–**	**(1,055)**	**29,056**
	8,744	**45,178**	**19,711**	**32,342**

	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)

(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 2025, gains totalling $53.9 million (2024: losses of $9.8 million) were recognised in respect of commodity contracts measured as FVPL. This included gains totalling $8.7 million (2024: losses of $12.9 million) realised on contracts that matured during the year, and mark-to-market unrealised gains totalling $45.2 million (2024: gains of $3.1 million).

The mark-to-market value of the Group's open commodity contracts as at 31 December 2025 was a net asset of $34.8 million (2024: net liability of $10.4 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 2025, gains totalling $24.1 million (2025: gains of $0.5 million) were recognised in the Group income statement. This included realised gains totalling $20.8 million (2024: gains 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 2025 was a net asset of $0.9 million (2024: net liability of $2.4 million).

(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 2025, gains totalling $28.0 million (2024: losses of $8.1 million) were recognised in the Group income statement. This included realised losses totalling $1.1 million (2024: losses of $7.6 million) on contracts that matured in the year.

The mark-to-market value of the Group's open contracts as at 31 December 2025 was a net asset of $20.3 million (2024: net liability of $8.7 million).

(f) Other receivables

	Other receivables $'000	Equity shares $'000	Total $'000
At 1 January 2024	**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**
Interest	**2,639**	–	**2,639**
Foreign Exchange	**2,804**	–	**2,804**
At 31 December 2025	**43,896**	**6**	**43,902**
Current			**–**
Non-current			**43,902**
			43,902

Other receivables 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 2025	**1,885,029,503**	**131,508**	**260,546**	**(4,425)**	**2,006**	**389,635**
Shares transferred to EBT	–	–	–	**885**	–	**885**
At 31 December 2025	**1,885,029,503**	**131,508**	**260,546**	**(3,540)**	**2,006**	**390,520**

At 31 December 2025, 20,000,000 (2024: 25,000,000) Ordinary shares were 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. During the year, 5,000,000 shares were transferred to the Company's EBT.

At 31 December 2025, there were 3,948,076 shares held by the EBT (2024: 972,269) which are included within the share-based payment reserve. The movement in the year was 2,975,807 shares used to satisfy awards made under the Company's share-based incentive schemes offset by a transfer of shares from Treasury.

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 (income)/expense recognised for each scheme was as follows:

	2025 $'000	2024 $'000
Performance Share Plan	**(806)**	511
Other performance share plans	**(8)**	64
Sharesave Plan	**145**	408
	(669)	983

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	**2025 Number**	2024 Number
Outstanding at 1 January	**88,617,683**	87,367,455
Granted during the year	**27,138,555**	35,353,664
Exercised during the year	**(1,493,821)**	(7,291,023)
Forfeited during the year	**(17,282,431)**	(26,812,413)
Outstanding at 31 December	**96,979,986**	88,617,683
Exercisable at 31 December	**15,172,474**	9,138,271

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.

	2025		2024	
Sharesave options	**Number**	**Weighted average exercise price $**	Number	Weighted average exercise price $
Outstanding at 1 January	**9,956,017**	**0.15**	18,658,144	0.16
Exercised during the year	**–**	**–**	(5,478,693)	0.13
Forfeited during the year	**(1,575,108)**	**0.21**	(3,223,434)	0.15
Outstanding at 31 December	**8,380,909**	**0.15**	9,956,017	0.15
Exercisable at 31 December	**155,925**	**0.28**	323,886	0.24

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 charge 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 2024	**451,333**	**21,961**	**473,294**
Unwinding of discount (see note 4(d))	**51,002**	**2,645**	**53,647**
Other change in fair value (see note 4(d))	**(442,335)**	**1,543**	**(440,792)**
Utilisation	–	**(1,529)**	**(1,529)**
At 31 December 2025	**60,000**	**24,620**	**84,620**
Classified as:			
Current	**60,000**	**318**	**60,318**
Non-current	**–**	**24,302**	**24,302**
	60,000	**24,620**	**84,620**

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.

In February 2026, an agreement was concluded with bp for EnQuest to settle the profit share arrangement for $60.0 million, with payment made the same month. As the agreement was substantially agreed at 31 December 2025, this value has been used to fair value the contingent consideration which resulted in a decrease in fair value (excluding the impact of unwind of discount) of $442.3 million (2024: decrease of $43.4 million). The decrease in 2024 reflected a reduction in the Group's near-term oil price assumptions and changes in the assets cost and production profile. The overall fair value accounting effect relating to the contingent consideration, including the unwinding of discount, totalled income of $391.3 million (2024: charge of $11.8 million) which was recognised in the Group income statement. Within the statement of cash flows, the profit share element of the repayment is disclosed separately under investing activities. There were no profit share payments during the year (2024: $48.5 million). At 31 December 2025, the contingent consideration for Magnus was $60.0 million (31 December 2024: $451.3 million).

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 2025, the amount due to bp calculated on an after-tax basis by reference to 30% of bp's decommissioning costs on Magnus was $24.6 million (2024: $22.0 million). Any reasonably possible change in assumptions would not have a material impact on the provision.

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 2024	**741,565**	**18,348**	**6,193**	**766,106**
Acquisition (see note 30)	**89,052**	**–**	**–**	**89,052**
Additions during the year(i)	**46,721**	**–**	**461**	**47,182**
Changes in estimates(i)	**40,868**	**4,772**	**(5,083)**	**40,557**
Unwinding of discount	**35,912**	**755**	**–**	**36,667**
Utilisation(ii)	**(38,486)**	**(8,589)**	**(481)**	**(47,556)**
Foreign exchange	**–**	**–**	**28**	**28**
At 31 December 2025	**915,632**	**15,286**	**1,118**	**932,036**
Classified as:				

	Decommissioning provision $'000	Thistle decommissioning provision $'000	Other provisions $'000	Total $'000
Current	**48,853**	**4,915**	**314**	**54,082**
Non-current	**866,779**	**10,371**	**804**	**877,954**
	915,632	**15,286**	**1,118**	**932,036**

(i) Includes $77.9 million related to producing assets disclosed in note 9 and $9.7 million relating to assets in decommissioning disclosed in note 4(d)
(ii) Utilisation differs to amounts paid in the cash flow statement due to movements in accruals recognised within trade and other payables

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. The Group's decommissioning provision has increased by $174.0 million in the period. This primarily reflects the discounted decommissioning liability acquired as part of the Vietnam asset acquisition of $89.1 million (which is largely pre-funded as set out below), additional liability recognised in relation to Seligi Non-Associated Gas rights in Malaysia of $41.5 million and higher cost estimates of $40.9 million, predominantly due to a weaker US Dollar, offset partly by the ongoing decommissioning programmes utilisation of $38.5 million.

At 31 December 2025, an estimated $364.3 million is expected to be utilised between one and five years (2024: $281.1 million), $373.1 million within six to ten years (2024: $280.0 million), and the remainder in later periods. For sensitivity analysis see Use of judgements, estimates and assumptions within note 2.

The Vietnam PSC requires the expected decommissioning liability to be pre-funded via a quarterly cash payment into an abandonment cess fund. The balance of amounts previously deposited into the cess fund is held in escrow to be drawn against when abandonment takes place. As at 31 December 2025, EnQuest's share of the cess fund was $92.1 million and is disclosed in non-current trade and other receivables (note 15).

The Group uses Letters of Credit, surety bonds and cash deposits to provide security for its decommissioning obligations. Following the agreement of a new RBL facility in November 2025, the Group utilised Letters of Credit totalling $381.5 million to provide security for its decommissioning obligations at 31 December 2025 (2024: surety bonds totalling $277.0 million and cash deposits of $53.4 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 2025, the amount due to bp by reference to 7.5% of bp's decommissioning costs on Thistle and Deveron was $15.3 million (2024: $18.3 million), with the reduction mainly reflecting the utilisation in the period. Change in estimates of $4.8 million are included within other expense (2024: $0.4 million) and unwinding of discount of $0.8 million is included within finance costs (2024: $0.9 million).

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. 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 sole signatory and the only party with the legal obligation to make lease payments to the lessor but the joint venture partners provide guarantees in relation to their share of the liability, the full lease liability will be recognised, along with the Group's share of the right-of-use asset and a receivable balance representing amounts owed by joint venture partners. 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 2023	**407,732**	**422,174**
Additions in the period	16,453	16,453
Depreciation expense	(54,735)	–
Impairment reversal	4,014	–
Interest expense	–	27,673
Payments	–	(130,065)
Foreign exchange movements	–	(980)
As at 31 December 2024	**373,464**	**335,255**
Acquisition (see note 30)	**33,002**	**60,681**
Additions in the period (see note 9)	**32,302**	**32,302**
Depreciation expense (see note 9)	**(59,184)**	**–**
Impairment reversal (see note 9)	**28,838**	**–**
Interest expense	**–**	**25,100**
Payments	**–**	**(83,061)**
Foreign exchange movements	**–**	**5,818**
Disposal	**(4,253)**	**(4,005)**
As at 31 December 2025	**404,169**	**372,090**
Current		**86,323**
Non-current		**285,767**
		372,090

The carrying value of the right-of-use assets include $373.9 million (2024: $340.9 million) of oil and gas assets and $30.3 million (2024: $32.6 million) of buildings.

The Group leases assets, including the Kraken and Vietnam FPSOs, property, and oil and gas vessels, with a weighted average lease term of three years. The maturity analysis of lease liabilities is disclosed in note 27.

Amounts recognised in profit or loss

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Depreciation expense of right-of-use assets	**59,184**	54,735
Impairment reversal of right-of-use assets	**(28,838)**	(4,014)
Interest expense on lease liabilities	**25,100**	27,673
Rent expense – short-term leases	**9,018**	13,860
Rent expense – leases of low-value assets	**297**	33

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Total amounts recognised in profit or loss	**64,761**	92,287

Amounts recognised in statement of cash flows

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Total cash outflow for leases	**83,061**	130,065

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 2025 was $1.9 million (2024: $2.2 million).

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

	2025 $'000	2024 $'000
Less than one year	**1,291**	2,029
One to two years	**1,293**	858
Two to three years	**1,310**	860
Three to four years	**1,317**	875
Four to five years	**821**	882
More than five years	**1,326**	1,856
Total undiscounted lease payments	**7,358**	7,360

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 2025 $'000	Year ended 31 December 2024 $'000
Deferred income	**138,095**	138,095

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 2025, the Group had commitments for future capital expenditure amounting to $48.4 million (2024: $13.3 million). The increase primarily relates to commitments for the development of the non-associated gas resources in the PM8/Seligi PSC contract area under the Seligi 1b gas agreement. The key remaining components of this relate to minimum work commitments in Indonesia and Brunei. 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 2025, the Group utilised Letters of Credit totalling $381.5 million under its new RBL facility to provide security for its decommissioning obligations, having held surety bonds totalling $277.0 million in 2024. 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. For example, in 2025, the NSTA engaged with EnQuest with regards to the timing/scheduling of certain plug and abandon obligations, which remain under discussion. Regardless, 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 2025 (2024: none).

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.

	2025 $'000	2024 $'000
Short-term employee benefits	**5,206**	5,138
Share-based payments	**30**	124
Post-employment pension benefits	**278**	226
Termination payments	**133**	947
	5,647	6,435

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 2025, 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 2025 and 2024, 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 production based on the proportion of the loan facility utilised. Where the relevant amounts utilised are 10% or less of the amounts available, the Group is required to hedge a minimum of 10% of volumes of net entitlement production expected in the next 12 months and the following 12 months. Where the relevant amounts utilised are more than 10% but less than 50% of the amounts available, the Group is required to hedge a minimum of 30% of volumes of net entitlement production expected in the next 12 months and a minimum of 15% of volumes of net entitlement production expected in the following 12 months. Where the relevant amounts utilised are 50% or more of the amounts available, the Group is required to hedge a minimum of 45% of volumes of net entitlement production expected in the next 12 months and a minimum of 30% of volumes of net entitlement production expected in the following 12 months.

Details of the commodity derivative contracts entered into during and open at the end of 2025 are disclosed in note 18. As of 31 December 2025, the Group held financial instruments (options and swaps) related to crude oil that covered 3.4 MMbbls of 2026 production and 0.9 MMbbls of 2027 production. The instruments have an effective average floor price of around $68.3/bbl in 2026 and $63.5/bbl in 2027. 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 2025.

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 2025	**(42,600)**	**42,900**
31 December 2024	(47,600)	47,200

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, the 9.00% retail bond, the vendor financing facility and any UK EPL cash tax payments which are 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 17% (2024: 12%) of the Group's sales and 98% (2024: 97%) 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 2025	**GBP $'000**	**MYR $'000**	**Other $'000**	**Total $'000**
Total financial assets	**357,349**	**30,762**	**12,015**	**400,126**
Total financial liabilities	**783,464**	**28,336**	**13,364**	**825,164**

Year ended 31 December 2024	GBP $'000	MYR $'000	Other $'000	Total $'000
Total financial assets	396,168	22,570	3,024	421,762

Year ended 31 December 2024	GBP $'000	MYR $'000	Other $'000	Total $'000
Total financial liabilities	714,626	21,731	3,801	740,158

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 2025	**(22,189)**	**22,189**
31 December 2024	(28,263)	28,263

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 2025, there were no trade receivables past due but not impaired (2024: nil) and no joint venture receivables past due but not impaired (2024: 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.

At 31 December 2025, the Group had one customer accounting for 65% of outstanding trade receivables (2024: two customers, 91%) and four joint venture partners accounting for over 75% of outstanding joint venture receivables (2024: four partners, over 70%).

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 2025, $409.8 million (2024: $194.3 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.

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 2025	**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	**–**	**60,888**	**–**	**–**	**–**	**60,888**
Bonds	**–**	**69,945**	**714,312**	**–**	**–**	**784,257**
Contingent consideration	**–**	**60,335**	**6,681**	**1,382**	**65,571**	**133,969**
Obligations under lease liabilities	**–**	**97,363**	**231,189**	**59,547**	**26,328**	**414,427**
Trade and other payables	**–**	**446,527**	**–**	**–**	**–**	**446,527**
	–	**735,058**	**952,182**	**60,929**	**91,899**	**1,840,068**

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	–	397,543	–	–	–	397,543
	–	587,573	205,572	1,189,144	456,723	2,439,012

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 2025	**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	**–**	**2,563**	**66**	**–**	**–**	**2,629**
Other derivative contracts	**–**	**43,411**	**7,485**	**22,015**	**–**	**72,911**
	–	**45,974**	**7,551**	**22,015**	**–**	**75,540**

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

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 (pages 12 to 16).

	2025 $'000	2024 $'000
Loans, borrowings and bond(i) (A) (see note 17)	**702,794**	666,073
Cash and cash equivalents (see note 13)	**268,846**	(280,239)
EnQuest net debt (B) (ii)	**433,948**	385,834
Equity attributable to EnQuest PLC shareholders (C)	**528,059**	542,466
Profit/(loss) for the year attributable to EnQuest PLC shareholders (D)	**1,562**	93,773
Adjusted EBITDA (F) (ii)	**503,823**	673,919
Gross gearing ratio (A/C)	**1.3**	1.2
Net gearing ratio (B/C)	**0.8**	0.7
EnQuest net debt/adjusted EBITDA (B/F) (ii)	**0.9**	0.6
Shareholders' return on investment (D/C)	**0.3%**	17.3%

(i) Principal amounts drawn, excludes netting off of fees and accrued interest (see note 17)
(ii) See Glossary – non GAAP measures on page 61

28. Subsidiaries

At 31 December 2025, 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 ENS Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Heather Leasing Limited(i)	Dormant	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) Limited[1]	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%
EnQuest Petroleum Developments Malaysia SDN. BHD(i)[3]	Exploration, extraction and production of hydrocarbons	Malaysia	100%
EnQuest Advance Holdings Limited(i)	Intermediate holding company	England	100%
EnQuest Advance Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%

Name of company	Principal activity	Country of incorporation	Proportion of nominal value of issued Ordinary shares controlled by the Group
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%
Premier Oil (Vietnam) Limited(i)4	Exploration, extraction and production of hydrocarbons	British Virgin Islands	100%
Premier Oil Vietnam Offshore B.V(i)5	Exploration, extraction and production of hydrocarbons	Netherlands	100%
EnQuest EP Gaea Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest EP Gaea II Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest EP BV Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%

(i) Held by subsidiary undertaking

The Group has five branches outside the UK (all held by subsidiary undertakings): EnQuest Global Services Limited (Dubai), EnQuest Global Services Limited (Bahrain), EnQuest Petroleum Production Malaysia Limited (Malaysia), Premier Oil Vietnam Offshore B.V (Vietnam) and EnQuest EP BV Limited (Brunei).

In January 2026, EnQuest Group Holdings Limited was incorporated in England and Wales as a holding company.

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 PO Box 3140, Road Town, Tortola, VG1110, British Virgin Islands
5 Lairessestraat 145 C,1075 HJ Amsterdam, the Netherlands

29. Cash flow information

Cash generated from operations

	Notes	**Year ended 31 December 2025 $'000**	Year ended 31 December 2024 $'000
Profit/(loss) before tax		**493,427**	166,614
Depreciation	4(c)	**5,129**	6,040
Depletion	4(b)	**267,299**	263,252
Exploration and appraisal expense	11	**173**	183
Net impairment (reversal)/charge to oil and gas assets	9	**(5,819)**	71,414
Net disposal/(write-back) of inventory		**2,800**	(5,539)
Share-based payment (credit)/charge	4(e)	**(669)**	983
Change in Magnus related contingent consideration	21	**(387,145)**	15,904
Change in provisions	22	**46,544**	39,116
Other non-cash UKA losses	4(b)	**11,490**	1,335
Unrealised (gain)/loss on commodity financial instruments	4(a)	**(45,178)**	(3,090)
Unrealised (gain)/loss on other financial instruments	4(b)	**(32,342)**	2,823
Unrealised exchange loss/(gain)		**21,973**	(8,714)
Net finance expense(i)		**118,700**	113,711
Operating cashflow before working capital changes		**496,382**	664,032
Decrease/(increase) in trade and other receivables		**38,656**	(4,561)
Decrease/(increase) in inventories		**12,366**	(5,786)
(Decrease)/increase in trade and other payables		**(49,585)**	32,261
Cash generated from operations		**497,819**	685,946

(i) Excludes unwind of discount on provisions (see note 5)

Changes in liabilities arising from financing activities

	Loans and borrowings $'000	Bonds $'000	Lease liabilities $'000	Total $'000
At 1 January 2024	**(311,210)**	**(471,019)**	**(422,174)**	**(1,204,403)**
Cash movements:				
Repayments of loans and borrowings	312,304	–	–	312,304
Proceeds from loans and borrowings	(26,928)	(160,000)	–	(186,928)
Payment of lease liabilities	–	–	130,065	130,065
Cash interest paid in year	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)**
Cash movements:				
Repayments of loans and borrowings(i)	**196,451**	**–**	**–**	**196,451**
Proceeds from loans and borrowings(ii)	**(217,420)**	**–**	**–**	**(217,420)**
Payment of lease liabilities	**–**	**–**	**83,061**	**83,061**
Cash interest paid in year(iii)	**4,130**	**69,884**	**–**	**74,014**
Non-cash movements:				
Additions	**20,448**	**–**	**(32,302)**	**(11,854)**
Disposals	**–**	**–**	**4,005**	**4,005**
Acquired (see note 30)	**–**	**–**	**(60,681)**	**(60,681)**
Interest/finance charge payable	**(6,027)**	**(69,269)**	**(25,100)**	**(100,396)**
Fee amortisation	**(2,927)**	**(4,505)**	**–**	**(7,432)**
Foreign exchange and other non-cash movements	**(21,007)**	**(12,365)**	**(5,818)**	**(39,190)**
At 31 December 2025	**(60,324)**	**(647,140)**	**(372,090)**	**(1,079,554)**

(i) Repayments of loans and borrowings include $120.0 million repaid under the previous RBL facility, $70.0 million under the new RBL facility, and $6.5 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 balance of the previous RBL facility at the date of refinancing of $50.0 million. This was fully repaid utilising the proceeds from the new facility and as such is netted against the proceeds of the new RBL facility in the Group Cash Flow Statement on the proceeds from loans and borrowings line

(ii) Proceeds from loans and borrowings include $120.0 million drawdown under the previous RBL facility prior to refinancing and $70.0 million under new RBL facility on refinancing, $6.7 million drawdowns under the SVT working capital facility and $20.7 million under the vendor loan facility. In the Group Cash Flow Statement, proceeds from loans and borrowings of $152.4 million include amounts outlined in the table above less the previous RBL facility balance of $50.0 million and associated new arrangement fees of $15.0 million. See note 17 for further details

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

Reconciliation of carrying value

	Loans (see note 17) $'000	Bonds (see note 17) $'000	Lease liabilities (see note 23) $'000	Total $'000
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)**
Principal	**(58,427)**	**(644,367)**	**(372,090)**	**(1,074,884)**
Unamortised fees	**–**	**6,156**	–	**6,156**
Accrued interest	**(1,897)**	**(8,929)**	–	**(10,826)**
At 31 December 2025	**(60,324)**	**(647,140)**	**(372,090)**	**(1,079,554)**

30. Business combination

Accounting policy

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, which is measured at acquisition date fair value, and the amount of any non-controlling interests in the acquiree. For each business combination, the Group elects whether to measure the non-controlling interests in the acquiree at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition-related costs are expensed as incurred and included in administrative expenses. The Group determines that it has acquired a business when the acquired set of activities and assets include an input and a substantive process that together significantly contribute to the ability to create outputs. The acquired process is considered substantive if it is critical to the ability to continue producing outputs, and the inputs acquired include an organised workforce with the necessary skills, knowledge, or experience to perform that process or it significantly contributes to the ability to continue producing outputs and is considered unique or scarce or cannot be replaced without significant cost, effort, or delay in the ability to continue producing outputs.

Acquisition of Block 12W Vietnam

The Group acquired a 53.125% interest in the Chim Sao and Dua fields ('Block 12W') in Vietnam from Harbour Energy on 9 July 2025 through acquisition of 100% of the share capital of two entities Premier Oil (Vietnam) Limited and Premier Oil Vietnam Offshore BV.

The Group acquired this business as it represents a key step in delivering the Group's diversified growth across South East Asia and aligns with its strategic aim to expand its footprint by investing in fast-payback assets with low capex and reduced carbon intensity. The Group acquired control through payment of cash.

The Transaction assets constitute a business and the acquisition has been accounted for using the acquisition method, in accordance with IFRS 3 Business Combinations. The fair values and resulting goodwill are provisional and will be finalised in EnQuest's half year 2026 financial statements.

The provisional fair values of the net identifiable assets as at the date of acquisition are as follows:

	Note	Fair value recognised on acquisition $'000
Non-current assets		
Property, plant and equipment	**9**	**24,716**
Right-of-use assets	**9**	**33,002**
Other receivables (i)	**15**	**111,787**
Current assets		
Trade and other receivables		**32,541**
Taxation receivable		**41**
Cash and cash equivalents		**5,850**
Total assets		**207,937**
Non-current liabilities		
Provisions(ii)	**22**	**89,052**
Lease creditor(iii)	**23**	**44,845**
Deferred tax	**6**	**6,063**
Current liabilities		
Trade and other payables		**30,546**
Lease creditor(iii)	**23**	**15,836**
Current tax liabilities		**1,002**
Total liabilities		**187,344**
Total identifiable net assets at fair value		**20,593**
Goodwill arising on acquisition		**5,110**
Purchase consideration transferred:		
Cash transferred		**25,703**
Total consideration		**25,703**

(i) Represents EnQuest's share of a central abandonment fund of $91.2 million which will be used to pay for future abandonment of the Vietnam asset and amounts owed by JV Partners of $20.6 million, with a further $7.1 million shown within current receivables in respect of the lease liability associated with the FPSO

(ii) Represents a decommissioning liability

(iii) Includes a lease liability predominantly in relation to the FPSO

	$'000
Analysis of cash flows on acquisition	
Total consideration	**25,703**
Net cash acquired with the subsidiaries	**(5,850)**
Transaction costs of the acquisition	**425**
Net cash flow on acquisition	**20,278**

The goodwill has arisen primarily due to the requirement to recognise deferred tax liabilities for the difference between the assigned fair values and the tax bases of the acquired assets and liabilities assumed in a business combination. The assessment of fair values of oil and gas assets acquired is based on cash flows after tax. Nevertheless, in accordance with IAS 12 Income Taxes, a provision is made for deferred tax corresponding to the tax rate multiplied by the difference between the acquisition date fair value and the tax base. The offsetting entry to this deferred tax is goodwill.

The acquisition date fair value of the trade receivables amounts to $0.3 million which is expected to be collected within contractual terms.

From the date of acquisition, the Transaction assets have contributed $52.8 million of revenue and $8.0 million to the profit before tax from continuing operations of the Group. If the combination had taken place at the beginning of the year, Group revenue from continuing operations would have been $1,162.9 million and the Group profit before tax from continuing operations would have been $508.4 million.

31. Subsequent events

On 26 February 2026, EnQuest paid bp $60.0 million as final settlement of the 75% profit share contingent consideration liability, securing 100.0% of future Magnus cash flows.

In February, EnQuest was notified by the Vietnam Ministry of Industry and Trade that it had been successful in extending the Block 12W PSC by four years to July 2034, on its existing terms. The PSC extension provides EnQuest and its joint venture partners with the opportunity to access upside across Block 12W and progress discovered resources into reserves, with prospectivity spread across three gas discoveries and several additional targets.

In February, EnQuest received a Letter of Award ('LOA') for a participating interest in the Cendramas PSC by Petronas. The terms of the LOA, subject to the finalisation and signing of the Joint Operating Agreement and the Cendramas PSC, are effective from 23 September 2026.

The Group continues to monitor the situation in the Middle East following the start of the conflict in February. At the date of this report, there has been no material disruption to the Group's day-to-day business.

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.

The Group adjusts 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	**2025 $'000**	2024 $'000
Net profit/(loss) (A)	**1,562**	93,773
Adjustments – remeasurements and exceptional items :		
Unrealised gains on derivative contracts (note 18)	**77,520**	267
Net impairment reversal/(charge) to oil and gas assets (note 9, note 10 and note 11)	**5,819**	(71,414)
Change in contingent consideration (notes 4(d))	**387,145**	(15,904)
Movement in other provisions (note 4(d))	**4,685**	–
Insurance income on Kraken shutdown and PM8/Seligi riser incident (see note 4(d))	**(53)**	1,663
Write-off of exploration costs (note 4(d))	**(173)**	(183)
Business acquisition transaction costs	**(425)**	–
Other non-cash UKA losses (note 4(b))	**(11,490)**	(1,335)
Drilling rig contract regret costs (note 4(d))	**–**	(14,629)
Pre-tax remeasurements and exceptional items (B)	**463,028**	(101,535)
Tax on remeasurements and exceptional items (C)	**(347,506)**	59,761
Post-tax remeasurements and exceptional items (D = B + C)	**115,522**	(41,774)
Adjusted net (loss)/ profit attributable to EnQuest PLC shareholders (A – D)	**(113,960)**	135,547

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	**2025 $'000**	2024 $'000
Reported profit from operations before tax and finance income/(costs)	**648,794**	311,528
Adjustments:		
Unrealised gains on derivative contracts (note 18)	**(77,520)**	(267)
Net impairment (reversal)/charge to oil and gas assets (note 9, note 10 and note 11)	**(5,819)**	71,414
Change in contingent consideration (notes 4(d))	**(387,145)**	15,904
Insurance income on Kraken and PM8/Seligi riser incident (see note 4(d))	**53**	(1,663)

Adjusted EBITDA	2025 $'000	2024 $'000
Licence write-off/write-off of exploration costs (see note 4(d))	**173**	183
Drilling rig contract regret costs (see note 4(d))	**–**	14,629
Depletion and depreciation (note 4(b) and note 4(c))	**272,428**	269,292
Inventory revaluation	**2,800**	(5,539)
Change in decommissioning and other provisions (note 4(d))	**9,814**	7,078
Business combination transaction costs (note 30)	**425**	–
Other non-cash UKA losses (note 4(b))	**11,490**	1,335
Net foreign exchange loss/(gain) (note 4(d))	**28,330**	(9,975)
Adjusted EBITDA (E)	**503,823**	673,919

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 pages 15 to 16.

Total cash and available facilities	2025 $'000	2024 $'000
Available cash	**265,886**	226,317
Restricted cash	**2,960**	53,922
Total cash and cash equivalents (F) (note 13)	**268,846**	280,239
Available undrawn facility (G)[(i)]	**409,795**	194,256
Total cash and available facilities (F + G)	**678,641**	474,495

[(i)]Includes amounts available under the RBL: $400.0 million (2024: $176.4 million) and vendor loan facility providing capacity for refinancing the payment of existing invoices up to an amount of £23.7 million): $9.8 million available (2024: $17.9 million)

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 pages 15 to 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	2025 $'000	2024 $'000
Loans and borrowings (note 17):		
SVT working capital facility	**36,331**	33,972
Vendor loan facility	**22,096**	-
Bonds (note 17):		
USD High yield bond	**458,844**	454,339
GBP Retail bond	**179,367**	167,101
Accrued interest	**10,826**	9,445
Loans and borrowings (H)	**707,464**	664,857
Non-cash accounting adjustments (note 17):		
Unamortised fees on bonds	**6,156**	10,661
Accrued interest	**(10,826)**	(9,445)
Non-cash accounting adjustments (I)	**(4,670)**	1,216
Debt (H + I) (J)	**702,794**	666,073
Less: Cash and cash equivalents (note 13) (F)	**268,846**	280,239
EnQuest net debt (J – F) (K)	**433,948**	385,834

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	2025 $'000	2024 $'000
EnQuest net debt (K)	**433,948**	385,834
Adjusted EBITDA (E)	**503,823**	673,919
EnQuest net debt/adjusted EBITDA (K/E)	**0.9**	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	2025 $'000	2024 $'000
Reported net cash flows (used in)/from investing activities	**(194,242)**	(182,435)
Adjustments:		
Payment of Magnus contingent consideration – Profit share	**–**	48,466

Cash capital and decommissioning expense	2025 $'000	2024 $'000
Proceeds from vendor financing facility receipt	**–**	(107,518)
Proceeds from Bressay farm-down	**–**	(1,263)
Acquisition	**20,278**	–
Interest received	**(5,286)**	(10,101)
Cash capital expenditure	**(179,250)**	(252,851)
Decommissioning expenditure	**(56,810)**	(60,544)
Cash capital and decommissioning expense	**(236,060)**	(313,395)

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	2025 $'000	2024 $'000
Net cash flows from/(used in) operating activities	**362,725**	507,631
Adjustments:		
Purchase of property, plant and equipment	**(175,025)**	(249,165)
Purchase of oil and gas intangible assets	**(4,225)**	(3,686)
Payment of Magnus contingent consideration	**–**	(48,466)
Estimated cash tax on disposal proceeds(i)	**–**	50,000
Interest received	**5,286**	10,101
Payment of obligations under finance lease	**(83,061)**	(130,065)
Interest paid	**(96,997)**	(83,162)
Adjusted Free cash flow	**8,703**	53,188

(i) Estimated by reference to disposal proceeds of $141.4 million and the EPL tax rate at that time 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	2025 $'000	2024 $'000
Revenue from crude oil sales (note 4(a)) (L)	**858,166**	1,020,266
Revenue from gas and condensate sales (note 4(a))	**200,526**	164,647
Realised gains/(losses) on oil derivative contracts (note 4(a)) (M)	**8,744**	(12,907)

Barrels equivalent sales	2025 kboe	2024 kboe
Sales of crude oil (N)	**12,595**	12,554
Sales of gas and condensate(i)	**2,678**	2,400
Total sales	**15,273**	14,954

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

Average realised prices	2025 $/Boe	2024 $/Boe
Average realised oil price, excluding hedging (L/N)	**68.1**	81.3
Average realised oil price, including hedging ((L + M)/N)	**68.8**	80.2

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	2025 $'000	2024 $'000
Total cost of sales (note 4(b))	**837,540**	787,383
Adjustments:		
Unrealised gains/(losses) on derivative contracts related to operating costs (note 4(b))	**32,342**	(2,823)
Depletion of oil and gas assets (note 4(b))	**(267,299)**	(263,251)
Charge relating to the Group's lifting position and inventory (note 4(b))	**(17,407)**	(2,172)
Other cost of operations(i) (note 4(b))	**(179,628)**	(134,984)
Other non-cash UKA losses	**(11,490)**	(1,335)
Operating costs	**394,058**	382,818
Less: realised gains/(losses) on derivative contracts (P) (note 4(b))	**19,711**	(4,735)

Operating costs	2025 $'000	2024 $'000
Operating costs directly attributable to production	**413,769**	378,083
Comprising of:		
Production costs (Q) (note 4(b))	**344,580**	307,634
Tariff and transportation expenses (R) (note 4(b))	**69,189**	70,449
Operating costs directly attributable to production	**413,769**	378,083

(i) Includes $166.2 million (2024: $125.7 million) of purchases and associated costs of third-party gas not required for injection activities at Magnus, which is sold on

Barrels equivalent produced	2025 kboe	2024 kboe
Total produced (working interest) (S)(i)	**15,675**	14,909

(i) Production 1,161 kboe associated with Seligi 1a gas (2024: 724 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	2025 $/Boe	2024 $/Boe
Production costs (Q/S)	**22.0**	20.6
Tariff and transportation expenses (R/S)	**4.4**	4.7
Total unit opex ((Q + R)/S)	**26.4**	25.3
Realised (gain)/loss on derivative contracts (P/S)	**(1.3)**	0.3
Total unit opex including hedging ((P + Q+ R)/S)	**25.1**	25.6