Harbour Energy plc
("Harbour" or the "Group" or the "Company")
Full Year Results
9 March 2023

Harbour Energy today announces its audited full year results for the year ended 31 December 2022.

Linda Z Cook, Chief Executive Officer, commented:
"In our first full year as a publicly listed company, Harbour delivered materially higher production which – together with improved margins – enabled us to continue to deleverage and make material shareholder distributions. We further developed our Net Zero strategy, setting ourselves an interim target, and built significant momentum in our flagship Viking CCS project. Most importantly we achieved all of this while improving our safety record.

However, the UK Energy Profits Levy, which applies irrespective of actual or realised commodity prices, has disproportionately impacted the UK-focused independent oil and gas companies that are critical for domestic energy security. For Harbour, the UK's largest oil and gas producer, it has all but wiped out our profit for the year. This has driven us to reduce our UK investment and staffing levels. Given the fiscal instability and outlook for investment in the country, it has also reinforced our strategic goal to grow and diversify internationally.

Thanks to our robust balance sheet, we enter 2023 well-placed to deliver on our strategy of building a global diverse oil and gas company. We will continue to return any excess capital to shareholders while investing in our existing portfolio and maintaining capacity for meaningful but disciplined M&A."

2022 Operational highlights

- Production of 208 kboepd (2021: 175 kboepd), a 19 per cent increase on 2021
- Improved unit operating costs of $13.9/boe (2021: $15.2/boe)
- Total recordable injury rate reduced to 0.8 per million hours worked (2021: 1.3)
- Investment decisions taken on Talbot development and Leverett appraisal in the UK
- Material discovery at Timpan-1 (Indonesia), de-risking a multi-TCF gas play
- Zama (Mexico) development plan substantially agreed ahead of submission to the regulator
- 2P reserves and 2C resources of 865 mmboe (2021: 948 mmboe), reflecting Indonesia exploration success offset by production and UK licence relinquishments
- Net Zero by 2035: Board-approved interim target to halve our emissions by 2030
- Viking CCS CO_2 storage resources of 300 mt independently verified; customer base expanded

2022 Financial highlights

- Realised, post hedging, oil and UK gas prices of $78/bbl and 86p/therm (2021: $59/bbl, 54p/therm)
- Increased EBITDAX of $4.0 billion (2021: $2.4 billion) and profit before tax of $2.5 billion (2021: $0.3 billion)
- Profit after tax of $8 million (2021: $101 million) impacted by a $1.5 billion one off non-cash deferred tax charge associated with the EPL
- Free cash flow of $2.1 billion (2021: $0.7 billion) after total capital expenditure of $0.9 billion (2021: $0.9 billion) and $551 million of tax payments (2021: $280 million)
- Approved $600 million of shareholder distributions: $553 million made in 2022; $41 million in 2023
- Net debt (excluding unamortised fees) and leverage reduced to $0.8 billion (2021: $2.3 billion) and 0.2x (2021: 0.9x), respectively
- Proposed final dividend of $100 million (12 cents per share) for 2022, in line with $200 million annual dividend policy; given our buybacks, this represents dividend per share growth of nine per cent

Outlook for 2023

- Production guidance of 185-200 kboepd reiterated; production to end February of 202 kboepd
- Opex guidance unchanged at c.$16/boe
- Total capex guidance reiterated at c.$1.1 billion, including c.$0.2 billion decommissioning, split 85 per cent UK / 15 per cent international
    - UK capex targeting high return, near field and/or infrastructure-led opportunities
    - International capex focused on growth opportunities with potential for material reserves replacement, including Zama (Mexico) and Andaman (Indonesia)
- Review of UK organisation to align with lower activity levels to complete in second half of 2023
- Continued efforts to reduce emissions and progress UK CCS projects to a final investment decision
- At $85/bbl, 150 pence/therm, forecast 2023 free cash flow (post-tax, pre-distributions) of c.$1.0 billion[1] with the potential to be net debt free in 2024
- New $200 million share buyback announced today which, together with the $200 million annual dividend policy, brings total announced shareholder returns to $1 billion since December 2021

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[1] The $1 billion of free cash flow is after tax payments and reflects that the majority of our 2023 EPL liability is expected to be paid in 2024 due to one of the Harbour entities not currently falling within the UK tax instalment payment regime.

Performance Review

Materially increased oil and gas production, supporting UK domestic energy supply

Production increased to 208 kboepd in 2022 (2021: 175 kboepd), towards the top end of our 195-210 kboepd original guidance and split equally between liquids and gas (2021: 55 per cent liquids, 45 per cent gas).

The almost 20 per cent increase in production was driven by new wells, primarily gas, coming online including at Tolmount, J-Area and Everest in the UK and by the full-year contribution from the Premier Oil assets. Our strong production performance was also supported by consistent outperformance from our Greater Britannia Area (GBA) satellite fields, Callanish and Brodgar. In addition, we benefited from shorter maintenance shutdowns and improved reliability.

Operating costs for the year were $1.1 billion, equating to $13.9/boe on a unit of production basis (2021: $15.2/boe). This improvement was driven by higher volumes and a weaker sterling to US dollar exchange rate. Total capital expenditure in 2022 was $0.9 billion (2021: $0.9 billion). This was lower than the $1.3 billion forecast at the outset of the year due to the decisions not to proceed with several North Sea exploration and appraisal wells and the delayed arrival of drilling rigs at multiple locations. Our operating and capital expenditure also reflected continued progress on integration, including supply chain savings as we consolidated key supplier contracts following recent acquisitions.

2023 production is forecast at 185-200 kboepd, with new wells coming on-stream partially offsetting natural decline. Our production mix is expected to remain stable at approximately 50 per cent liquids, 50 per cent gas. The outlook for unit operating cost for 2023 is c.$16/boe, higher than in 2022 because of lower production and some inflationary pressures.

2023 total capital expenditure is estimated at $1.1 billion, split 85 per cent UK, 15 per cent international. We reduced our planned 2023 UK capital expenditure following the changes to the Energy Profits Levy (EPL) announced in November, with certain investment opportunities delayed or no longer being progressed. We also rephased some of our decommissioning activities.

Safe and responsible operator

Harbour delivered an improved safety performance in 2022. With nearly 12 million hours worked during the year, we recorded no serious injuries or significant spills and materially reduced our total recordable injury rate per million hours to 0.8 (2021: 1.3). However, we did experience an uptick in high potential incidents through the first half of the year reminding us of the need to remain vigilant as we strive to meet our 'zero incident' ambition.

Harbour is committed to proactively addressing its environmental impact and to achieving its 2035 net zero goal. In 2022, our emissions intensity across our operated assets was broadly stable at 21 kgCO_2e/boe (2021: 21 kgCO_2e/boe[1]), despite a full year's contribution from the more emissions-intensive Premier Oil assets. The performance reflects improved efficiency and the implementation of emissions-reduction projects within our operated hubs. 2022 also saw us further develop our net zero strategy, setting an interim target of 50 per cent reduction in our emissions by 2030 versus a 2018 baseline and aligning our emissions definitions and targets more closely with industry standards.

Targeted UK capital investment programme

Harbour's UK capital investment is focused on high return, lower risk, near field and infrastructure-led opportunities which add reserves, improve recovery and extend producing life, activities all critical to the UK's energy security. During 2022, we completed c.50 well intervention programmes and brought online 14 new wells. In total, we developed over 35 mmboe of 2P reserves, volumes that are now contributing to our production.

In April, we brought the Tolmount gas project on-stream which reached gross plateau rates of 40 kboepd (Harbour 50 per cent interest) in July, increasing the UK's domestic gas supply by approximately five per cent at a critical time. The project reached cash payback in September and has since come off plateau production, earlier than originally anticipated. Post-period end we completed the Tolmount East development well which is expected online in 2024, while the near field Earn prospect is scheduled to be tested in the second half of 2023.

At J-Area, the successful Jade South exploration well was brought into production in January 2022 helping boost production levels from the hub. Two J-Area infill wells were brought online around the end of the year, one of which has performed below expectations. Another near field exploration well, targeting the Jocelyn South prospect, is planned for the second half of 2023. We also completed a three well drilling programme at Catcher, two of which were brought on-stream around the year-end. The third encountered sub-commercial volumes and was not completed.

[1] 2021 GHG intensity has been restated in line with our emissions reporting boundaries which were updated in 2022.

In our non-operated portfolio, Clair Ridge production continues to be supported by an ongoing development programme with two producer and water injector wells completed during 2022. The operator also plans to return to platform drilling at Clair Phase 1 during the first half of 2023. At Beryl, production was impacted by underperformance of the Storr-2 well which came online during the first quarter of 2022 and delays to the Buckland South West well which is expected on-stream in the second quarter of 2023. Further drilling is planned at Beryl during 2023, although less than forecast at the outset of the year following the operator's decision to terminate its drilling contract for the Ocean Patriot.

2022 saw us approve the Talbot oil development comprising a multi-well subsea tieback to our Judy platform. Development drilling is expected to commence in the first half of 2023 with the start of production scheduled for around the end of 2024. We also approved the appraisal of the Leverett gas discovery, located close to the Greater Britannia Area, with the well scheduled to spud in the second quarter of 2023.

We continue to invest in high return investment opportunities to maximise value from our producing asset base. However, the changes to the EPL announced in November have caused us to scale back our UK investment levels in certain areas and to review our UK organisation. The review, which is targeted for completion in the second half of 2023, is expected to lead to a significant reduction in our UK workforce.

Attractive international growth projects with potential for material reserves replacement

Our aim is to grow and diversify internationally via acquisitions. We seek to acquire cash generative producing assets which are accretive to our reserve life, margins and GHG intensity thereby improving our credit rating and ability to support shareholder returns over the longer term. While market conditions were challenging for acquisitions during 2022, there are signs of a more active M&A market in 2023.

In addition, we have several organic growth projects which together could add materially to our reserves and future production. In Mexico, Harbour has a 12.39 per cent non-operated interest in the Zama unit where the Block 7 partners and Pemex have substantially agreed the field development plan ahead of targeted submission to the Mexican regulator by the end of the first quarter of 2023. Front-End Engineering and Design work (FEED) is planned for 2023, along with an update of project cost estimates, ahead of a final investment decision.

In Indonesia, we made a material offshore gas discovery with the play-opening Timpan-1 well on our Andaman II licence in July. As a result, we acquired 3,400 km^2 of 3D seismic across the eastern part of the Andaman II licence at the end of 2022 and plan to drill at least three exploration and appraisal wells across our Andaman acreage beginning in the second half of 2023.

Elsewhere in Indonesia the government approved a plan of development for the Tuna field in December. However, further progress has been impacted by EU and UK sanctions which limit our ability as operator to provide certain services to our Russian partner in the Tuna licence. We are working with our partner to reach a solution to enable us to progress the project in 2023.

Maturing our 2P reserves and 2C resources to support production and reserves replacement

As at 31 December 2022, Harbour's proven and probable (2P) reserves on a working interest basis were 410 mmboe (2021: 488 mmboe), reflecting the impact of 2022 production. While we made progress maturing 2C resources into 2P reserves, including at J-Area and Greater Britannia Area, this was offset by a downward revision at the Tolmount field based on pressure and other performance data.

Harbour's 2C resources stood at 455 mmboe as at 31 December 2022 (2021: 460 mmboe). This reflects the material addition of the Timpan gas discovery in Indonesia, offset by the movement of some volumes to 2P reserves and relinquishments and revisions following the high grading of our remaining UK 2C portfolio.

Investing in the energy transition

Harbour is well positioned to contribute to the energy transition through our CCS projects, utilising our skills, infrastructure and 40 years' knowledge of operating in the North Sea, and through responsibly decommissioning retired oil and gas infrastructure which cannot be repurposed for CCS.

During 2022, we made significant progress on our flagship CCS project, Viking. We completed pre-FEED work and concluded non-statutory and statutory consultations for the onshore pipeline. In addition, we had our contingent CO_2 storage resources of 300 million tonnes independently evaluated by ERCE via a Competent Person's Report, we believe the first project in the UK and only the third in the world to have done so.

We materially expanded the project's future customer base through early commercial agreements with West Burton Energy and RWE, whilst maintaining strong technical progress under existing agreements with

Phillips 66 and VPI. As a result, the Viking CCS cluster has the potential to capture, transport and store 10 mtpa of CO_2 by 2030 and 15 mtpa by 2035, materially contributing to the UK's goal of 20 to 30 mtpa by 2030. We also entered into an exclusive commercial relationship with Associated British Ports who are advancing plans to develop a CO_2 import terminal at Immingham, enabling the potential for shipped CO_2 (domestic and imported) to be transported and stored by Viking CCS.

Harbour, together with its partners, continued to progress the Acorn project in Scotland which has the potential to store up to 9 mtpa of CO_2. Subject to receiving clarity from the UK Government on the fiscal, regulatory and commercial framework, Harbour is aiming to progress Viking and Acorn to final investment decisions in 2024, with first CO_2 injection as early as 2027.

During 2022, Harbour's decommissioning team continued to deliver a strong safety and environmental performance. In the southern North Sea, we successfully plugged and abandoned seven wells, removed seven platforms and completed an extensive post removal seabed remediation campaign.

In total during 2022, Harbour spent c.$300 million on our energy transition activities including the decommissioning of non-producing oil and gas facilities, our CCS activities and projects to reduce our own emissions.

A solid financial position

During 2022, we generated free cash flow of $2.1 billion (2021: $0.7 billion). The significant increase was driven by higher production levels and the improved commodity price environment offset by hedging losses and significantly increased cash tax payments. Our realised oil and gas prices were $78/bbl and 86 pence/therm, materially below the average Brent and UK NBP gas prices of $101/bbl and 198 pence/therm due to our historical hedging programme.

Our cash flow generation enabled us to rapidly deleverage our balance sheet during 2022 with net debt (excluding unamortised fees) reducing to $0.8 billion (2021: $2.3 billion) and leverage (net debt/EBITDAX) reducing to 0.2x (2021: 0.9x).

As a result of this strong financial performance, our Board approved $400 million of share buybacks during the year, in addition to our $200 million annual dividend. As a result of the share buybacks, $361 million of which was completed in 2022 and $41 million in 2023, we repurchased and cancelled 9.7 per cent of our issued share capital.

In line with our stated dividend policy to pay ordinary dividends of $200 million per annum, the Board has declared a final dividend of $100 million in respect of the 2022 financial year to be paid in May 2023, subject to shareholder approval.

2022 saw the introduction of the UK EPL, which was subsequently increased and extended, taking our UK headline tax rate to 75 per cent until March 2028. The EPL has disproportionately impacted UK focused independent oil and gas companies. For Harbour, the largest oil and gas producer in the UK, it has all but extinguished our profit for the year, necessitated a review of our future activity and staffing levels in the country and reinforced our strategic goal to grow and diversify internationally.

Outlook for 2023

Harbour enters 2023 well placed to deliver on its strategy of building a global, diverse oil and gas company, supported by a cash-generative asset base, a robust balance sheet, disciplined capital allocation and a prudent approach to risk management. We will continue to return any excess capital to shareholders while investing in our existing portfolio and maintaining capacity for meaningful M&A. As a result, the Board has approved a $200 million share buyback programme. This, together with our $200 million annual dividend policy, brings total announced shareholder returns to $1 billion since December 2021.

At $85/bbl and 150 pence/therm average oil and gas prices, we forecast 2023 free cash flow of c.$1 billion and have the potential to be net debt free in 2024 following increased shareholder returns.

Financial Review

These 2022 results represent the first full year for Harbour through to 31 December 2022.

The 2021 comparative results for the income statement are representative of three months of Chrysaor (January to March 2021) and nine months of Harbour (April to December 2021, post-merger of Chrysaor and Premier Oil on 31 March 2021).

Summary of financial results

	2022	2021
Production and post-hedging realised prices		
Production – kboepd	**208**	175
Crude oil - $/boe	**78**	59
UK natural gas – p/therm	**86**	54
Indonesia natural gas - $/mscf	**14**	12
Income statement		
Revenue and other income - $ million	**5,431**	3,618
EBITDAX (1)- $ million	**4,011**	2,431
Profit before taxation - $ million	**2,462**	315
Profit after taxation - $ million	**8**	101
Basic earnings per share - $/share	**0.0**	0.1
Other financial key figures		
Total capital expenditure (1) - $ million	**907**	935
Operating cash flow - $ million	**3,130**	1,614
Free cash flow (1) - $ million	**2,105**	678
Shareholder returns paid - $ million	**553**	-
Net debt (after unamortised fees) (1) - $ million	**704**	2,147
Leverage ratio (1)	**0.2**	0.9

(1) See Glossary for the definition of non-IFRS measures. Reconciliations between IFRS and non-IFRS measures are provided within this review.

Income Statement

	2022 $ million	2021 $ million
Revenue and other income (note 4)	**5,431**	3,618
▪ **Crude**	**2,792**	2,023
▪ **Gas**	**2,322**	1,264
▪ **Condensate**	**238**	164
▪ **Tariff income and other revenue**	**38**	28
▪ **Other income**	**41**	139
EBITDAX	**4,011**	2,431
Operating profit	**2,541**	640
Profit before taxation	**2,462**	315
Taxation	**(2,454)**	(213)
Profit after tax	**8**	101

	$/share	$/share
Basic earnings per share	**0.0**	0.1

Revenue and other income
Total revenue and other income increased to $5,431 million (2021: $3,618 million). This was driven by the increase in production, especially UK gas production, which was 34 per cent higher compared to 2021, and higher post-hedging realised prices.

Revenue earned from hydrocarbon production activities increased to $5,352 million (2021: $3,451 million) after realised hedging losses of $3,185 million (2021: $1,517 million). Some of our hydrocarbon production is sold pursuant to fixed-price contracts. The rest is sold at market values, subject to standard quality and basis adjustments.

Crude oil sales increased to $2,792 million (2021: $2,023 million), with a realised post-hedging oil price of $78/bbl (2021: $59/bbl).

Gas revenue was $2,322 million (2021: $1,264 million), split between UK natural gas revenue of $2,142 million (2021: $1,143 million) and international gas revenue of $180 million (2021: $121 million). The realised post-hedging price for our UK and Indonesia gas was 86 pence/therm (2021: 54 pence/therm) and $14.2/mscf (2021: $11.7/mscf), respectively.

Other income amounted to $41 million (2021: $139 million). The reduction on the prior year was driven by mark-to-market losses on European Union Agency emissions hedges of $3 million (2021: gains of $51 million) and a consideration adjustment of $40 million received from ConocoPhillips included in 2021 other income. Further detail can be found in note 4.

Cost of Operations

	2022 $ million	2021 $ million
Operating costs		
Field operating costs[(1)]	1,087	1,003
Tariff income	(30)	(27)
Total	1,057	976
Operating costs per barrel ($ per barrel)	13.9	15.2
Depreciation, depletion and amortisation (DD&A) before impairment charges		
Depreciation of oil and gas properties (cost of operations only)	1,507	1,327
Depreciation of non-oil and gas properties	38	42
Amortisation of intangible assets	1	2
Total	1,546	1,371
DD&A before impairment charges ($ per barrel)	20.4	21.4

(1) Includes mark-to-market losses of $3 million on EUA emissions hedges included in Other revenue (2021: gains of $51 million), excludes non-cash depreciation on non-oil and gas assets.

Cost of operations increased to $2,845 million (2021: $2,453 million) reflecting a full year contribution from the Premier Oil assets and the addition of the Tolmount field, partially offset by a foreign exchange benefit from the pound sterling weakening against the US dollar. Unit operating costs equated to $13.9/boe (2021: $15.2/boe) with the reduction largely due to higher production volumes.

Depreciation, depletion and amortisation (DD&A) unit expense, which reflects the depreciation of capitalised producing assets costs over production, was $20.4/boe (2021: $21.4/boe).

EBITDAX

EBITDAX increased to $4,011 million (2021: $2,431 million), driven by higher production and higher commodity prices, partially offset by higher operating costs.

	2022 $ million	2021 $ million
Operating profit	**2,541**	**640**
Depreciation, depletion and amortisation	1,546	1,371
Impairment/(reversals) of property, plant and equipment	(170)	117
Exploration and evaluation and new ventures	42	50
Exploration costs written-off	64	255
Gain on disposal	(12)	-
Provision for onerous contracts	-	(2)
EBITDAX	**4,011**	**2,431**

Impairments and reversals

The Group has recognised a net pre-tax impairment reversal of $170 million (2021: $117 million charge) which consists of three items.

First there was a single impairment of $163 million relating to one of our North Sea producing fields. This is due to the contracted price we realise for our crude sales being negatively impacted by the pricing differential between Urals and Brent crude and a revised operating cost profile for the field.

The price provisions in the contract are currently the subject of a dispute with the buyer.

Second, the Group has recognised impairment reversals of $251 million (2021: nil) on North Sea gas assets that were previously impaired. This was primarily driven by higher gas price assumptions for UK natural gas.

Finally, the Group recognised an impairment credit of $82 million (2021: $9 million charge) in respect of revisions to decommissioning estimates on the Group's non-producing assets.

Exploration and evaluation expenditure and new ventures
During the year, the Group expensed $106 million (2021: $305 million) for exploration and appraisal activities. This includes: exploration write-off expense of $64 million (2021: $255 million), following a technical review of our UK exploration asset portfolio; $42 million (2021: $50 million) related to pre-development costs of which $28 million (2021: $14 million) was associated with our UK CCS and electrification projects; and ongoing pre-licence expenditure of $14 million (2021: $36 million).

Net financing costs
Finance income increased to $279 million (2021: $49 million). This was driven by increased foreign exchange gains of $202 million (2021: losses of $65 million shown as finance expense) reflecting the weakening of the UK pound sterling against the US dollar. In particular, this included unrealised foreign exchange gains arising predominantly on the revaluation of open sterling denominated UK gas hedges using a significantly lower sterling US dollar exchange rate. Finance income also includes gains of $38 million (2021: $15 million) on interest rate and foreign currency derivatives.

Finance expenses amounted to $358 million (2021: $375 million). This included interest expense incurred on debt facilities of $98 million (2021: $113 million), the reduction reflecting the impact of lower drawn down debt partially offset by higher interest rates. Other financing expenses include the unwinding of the discount on provisions, primarily associated with future decommissioning obligations, of $65 million (2021: $78 million) and bank and financing fees of $91 million (2021: $63 million). 2021 included foreign exchange losses of $65 million as noted above.

Further detail on finance income and expense can be found in note 6.

Earnings and taxation
Profit after tax amounted to $8 million (2021: $101 million), with increased profit before tax almost wholly offset by the negative impact of the introduction of the EPL in the UK. This resulted in earnings per share of $0.0 (2021: earnings $0.1) after taking into account the weighted average number of ordinary shares in issue of 900 million (2021: 871 million) following the share buyback programme. Whilst the number of shares reduced during 2022 due to the share buyback programs, the weighted number of shares increased during 2022 compared to 2021 due to the impact of the reverse acquisition effective 1 April 2021.

During 2022 the UK Government both enacted the EPL and subsequently increased it and extended its duration. The EPL applies an additional 25 per cent tax on profits earned from the production of UK oil and gas from 26 May 2022, increasing to 35 per cent from January 2023 to March 2028, irrespective of actual market or realised oil and gas prices.

Harbour's tax expense increased in 2022 to $2,454 million (2021: $213 million), primarily driven by the introduction of the EPL.

The tax expense is split between a current tax expense of $706 million (2021: $192 million), which includes an EPL current tax charge of $326 million, and a deferred tax expense of $1,748 million (2021: $21 million). Of the deferred tax expense, $1,469 million relates to a one-off non-cash deferred tax charge due to the introduction of the EPL of which $148 million reversed in the period. This arises because the deferred UK tax position on our balance sheet has been revalued from 40 per cent to 75 per cent where relevant to reflect the increase in our future tax rate in the period to

March 2028. The total tax charge therefore includes a total of $1,647 million in relation to the EPL.

The effective tax rate is 100 per cent (2021: 68 per cent) materially higher than the blended standard UK tax rate for the period of 55 per cent. This increase is driven by the one off deferred tax charge associated with the introduction of the EPL partially offset by the profits from our international assets being subject to a lower tax rate.

Shareholder distributions
A final dividend with respect to 2021 of 11 cents per ordinary share was proposed on 17 March 2022 and approved by shareholders at the AGM on 11 May 2022. The dividend was paid on 18 May 2022 to all shareholders on the register as at 8 April 2022, totalling $98 million. An interim dividend was announced on 25 August at 11 cents per share and was paid on 19 October 2022 at a value of $93 million.

In addition to these dividend payments, the Board approved $400 million of share buybacks during 2022. During 2022, we repurchased and cancelled 78.4 million of our shares at a cost of $361 million[1] (2021: $nil). Post period end in February 2023, the remaining $41 million[1] of the 2022 approved share buybacks was concluded with the repurchase and cancellation of 11.1 million shares. As a result, the total number of shares repurchased and cancelled under the $400 million of share buybacks was 89.5 million shares equating to 9.7 per cent of our issued share capital.

The Board is proposing final dividend with respect to 2022 of 12 cents per ordinary share to be paid in GBP at the spot rate prevailing on the record date. This dividend is subject to shareholder approval at the AGM, to be held on 10 May 2023. If approved, the dividend will be paid on 24 May 2023 to shareholders on the register as of 14 April 2023. A dividend re-investment plan (DRIP) is available to shareholders who would prefer to invest their dividends in the shares of the company. The last date to elect for the DRIP in respect of this dividend is 28 April 2023.

The Board has approved a new $200 million share buyback programme to commence shortly. It is anticipated that an irrevocable non-discretionary agreement will shortly be entered into with the Company’s corporate brokers to execute the programme on the Company’s behalf. The purpose of the programme is to reduce the Company’s share capital and all ordinary shares purchased as part of this programme will be cancelled. The programme will end no later than 31 December 2023. Any purchases of ordinary shares by the Company in relation to this announcement will be conducted in accordance with the relevant regulations (including but not limited to the Listing Rules) and Harbour's general authority to repurchase shares, a renewal of which will be sought at the Company’s AGM in May.

[1] Total spend on share buybacks includes transaction fees and foreign exchange differences applied to the Sterling denominated shares repurchased.

Statement of Financial Position

	2022 $ million	2021 $ million
Assets		
Total non-current assets, excluding deferred taxes	9,032	10,273
Deferred tax assets (note 7)	1,407	1,938
Total current assets	2,127	2,294
Total assets	***12,566***	***14,505***
Liabilities and equity		
Total borrowings net of transaction fees (note 13)	1,238	2,886
Total decommissioning provisions (note 12)	4,141	5,354
Deferred tax liabilities (note 7)	397	187
Lease creditor (note 11)	825	654
Derivative liabilities (note 14)	3,451	3,538
Other liabilities	1,493	1,412
Total liabilities	***11,545***	***14,031***
Equity	***1,021***	***474***
Total liabilities and equity	***12,566***	***14,505***
***Net debt* (note 15)**	***(704)***	***(2,147)***

Assets
At 31 December 2022, total assets amounted to $12,566 million (2021: $14,505 million), of which current assets were $2,127 million (2021: $2,294 million). The decrease in total assets of $1,939 million is mainly as a result of a reduction in the deferred tax asset (see note 7) of $531 million and a reduction in property, plant and equipment of $1,557 million (see note 10), partially offset by the increase in right-of-use assets of $183 million (see note 11). The reduction in property, plant and equipment is partly due to the reduction in the decommissioning assets of $778 million (2021: $358 million) primarily as a result of an increase in the risk-free rate applied to the corresponding decommissioning provisions (see note 12).

The net deferred tax position on the balance sheet is an asset of $1,009 million. This balance mainly reflects future tax relief available on decommissioning of $1,565 million, cash flow hedge derivatives of $2,452 million and tax losses of $569 million offset by additional tax expected to be paid on property, plant and equipment (PP&E) of $3,396 million along with deferred tax related to overseas operations and other of $181 million.

The introduction of the EPL has resulted in a net $355 million decrease on deferred tax asset in the balance sheet as the increased deferred tax liability of $1,470 million associated with PP&E which impacts the income statement is offset by the increased deferred tax asset of $1,115 million associated with the cash flow hedge derivatives loss in the period which flows through the other comprehensive income statement.

Liabilities
At 31 December 2022, total liabilities amounted to $11,545 million (2021: $14,031 million). The reduction in liabilities was mainly driven by a reduction in the decommissioning provisions by $1,213 million, and a reduction in borrowings of $1,648 million in relation to the reserves-based lending (RBL) facility. The decommissioning provision reduction was primarily due to an increase in the risk-free rate used in the estimate, as well as the changes in cost estimates used and currency translation adjustments; refer to note 12 for more detail.

Equity and reserves
Total equity amounted to $1,021 million (2021: $474 million) with the increase mainly due to the gains in comprehensive income related to gains on cash flow hedges of $269 million (2021: losses $3,584 million) and movements in tax on cash flow hedges of $1,006 million (2021: $1,433 million) offset by currency translation movements of $198 million (2021: $6 million), share buybacks of $361 million and dividend payments of $192 million made in the year. Retained earnings were marginally increased by the profit after tax.

Net debt
As at 31 December 2022, after unamortised fees, net debt of $704 million (2021: $2,147 million) consisted of $775 million (2021: $2,438 million) drawn on the reserves-based lending facility (RBL), the $500 million (2021: $500 million) bond and an exploration financing facility (EFF) of $11 million (2021: $45 million) less unamortised deferred fees of $82 million (2021: $136 million) and cash balances of $500 million (2021: $699 million). The decrease in the year is mainly due to the repayments on the RBL facility.

Available liquidity, being undrawn RBL facility plus cash balances, was $2.5 billion at the end of the year.

Derivative financial instruments
We carry out hedging activity to manage commodity price risk, to ensure we comply with the requirements of the RBL facility and to ensure there is sufficient funding for future investments. We have entered into a series of fixed-price sales agreements and a financial hedging programme for both oil and gas, consisting of swap and option instruments. Our future production volumes are hedged under the physical and financial arrangements in place at 31 December 2022. These are set out in the following table. Hedges realised to date are in respect of both crude oil and natural gas.

The current hedging programme is shown below:

Hedge position	**2023**	**2024**	**2025**	**2026**
Oil				
Volume hedged (mmboe)	10.95	7.32	2.37	-
Average price hedged ($/bbl)	74.08	84.37	81.22	-
UK natural gas				
Volume hedged (mmboe)	23.08	11.25	1.94	-
Average priced hedged (p/therm)	41.46	68.85	75.22	-

At 31 December 2022, our financial hedging programme on commodity derivative instruments showed a pre-tax negative mark-to-market fair value of $3,259 million (2021: $3,506 million), with no ineffectiveness charge to the income statement. Refer to note 14 for more information.

Statement of cash flows [1]

	2022 $ million	2021 $ million
Cash flow from operating activities after tax	**3,130**	**1,614**
Cash flow from investing activities – capital investment	(634)	(644)
Cash flow from investing activities – acquired on business combinations	-	97
Cash flow from investing activities – other	5	(24)
Operating cash flow after investing activities	**2,501**	**1,043**
Cash flow from financing activities [2]	(396)	(365)
Free cash flow [3]	***2,105***	***678***
Cash and cash equivalents	***500***	***699***

(1) Table excludes financing activities related to debt principal movements.

(2) Net of interest and lease payments

(3) Free cash flow is calculated as operating cash flow less cash flow from investing activities less interest and lease payments and is before shareholder distributions.

Net cash from operating activities after tax amounted to $3,130 million (2021: $1,614 million). This is after tax payments of $551 million (2021: $280 million), split $513 million in the UK and $38 million overseas, and positive working capital movements of $53 million (2021: negative $607 million).

Cash flow used in investing activities on capital expenditure was $634 million (2021: $644 million). Cash outflow from financing activities for lease payments, interest and charges paid was $396 million (2021: $365 million).

Cash flow from financing activities includes dividends paid of $192 million (2021: $nil) and $361 million (2021: $nil) related to the repurchase of Harbour's own shares through the share buyback programmes undertaken during 2022.

Cash balances were $500 million (2021: $699 million) at the end of the period.

Capital investment is defined as additions to property, plant and equipment, fixtures and fittings and intangible exploration and evaluation assets, excluding changes to decommissioning assets.

	2022 $ million	2021 $ million
Additions to oil and gas assets (note 10)	(532)	(464)
Additions to fixtures and fittings, office equipment & IT software (note 9 and note 10)	(41)	(35)
Additions to exploration and evaluation assets (note 9)	(111)	(210)
Total capital investment [1]	***(684)***	***(709)***
Movements in working capital	28	42
Capitalised lease payments (note 11)	22	23
Cash capital expenditure per the cash flow statement	***(634)***	***(644)***

(1) Non-IFRS measure

During the period, the Group incurred total capital expenditure of $907 million (2021: $935 million), split capital investment $684 million (2021: $709 million) and decommissioning spend $223 million (2021: $226 million).

The capital investment mainly consisted of operated drilling on the J-Area at the Jade, Judy and Jill fields, Catcher development wells and non-operated drilling programmes on the Clair Ridge platform. The decommissioning expenditure mainly relates to activity in the southern North Sea and Balmoral area in the UK Central North Sea.

Principal risks
There are no significant changes to the headline principal risks from those disclosed in the 2022 half year results.

Post balance sheet events
On 14 February 2023, the company's defined benefit pension scheme's (the 'Scheme') trustee effected a bulk annuity 'buy in' policy with Just Retirement Limited. This policy secures the benefits of all the Scheme's members and eliminates mortality and investment risk from the company's balance sheet. This decision was made principally in light of the substantial improvement to the Scheme's funded status over 2022 and the favourable market conditions for such transactions. The company was not required to pay any additional contributions to the Scheme in respect of the annuity purchase.

Going concern
The Group monitors its capital position and its liquidity risk regularly throughout the year to ensure it has access to sufficient funds to meet forecast cash requirements for the period twelve months after the approval of the accounts until March 2024. Cash forecasts are regularly produced based on, inter alia, the Group's latest life of field production and expenditure forecasts, management's best estimate of future commodity prices (based on recent forward curves, adjusted for the Group's hedging programme) and the Group's borrowing facilities.

The Group's base case going concern assessment is based upon management's best estimate of forward commodity price curves and uses production in line with approved asset plans and the ongoing capital requirements of the Group will be financed by existing RBL and bond financing arrangements.

In line with the principal risks, sensitivity analyses have been prepared to reflect the combined impact of reductions in crude and UK natural gas prices of 20 per cent on unhedged production and in the Group's production of 10 per cent throughout the going concern period. In these combined downside scenarios applied to the base case forecast, the Group is forecasted to have sufficient financial headroom throughout the going concern period.

Further, reverse stress tests have been prepared reflecting further reductions in commodity price and production parameters, prior to any mitigation strategies, to determine what levels each would need to reach such that either lending covenants are breached, or financial liquidity headroom runs out. The results of this reverse stress test demonstrated the likelihood of the fall in price and production parameters required to cause a risk of funds shortfall or covenant breaches is remote.

Taking the above into account the Board was satisfied that for the going concern period, the Group was able to maintain adequate liquidity and no covenant breaches occurred and therefore has adopted a going concern basis for preparing the financial statements.

Consolidated income statement

For the year ended 31 December

	Note	*2022* *$ million*	*2021* *$ million*
Revenue	4	5,390.0	3,478.8
Other income	4	41.2	139.2
Revenue and other income		5,431.2	3,618.0
Cost of operations	5	(2,844.8)	(2,453.2)
Impairment reversal/(impairment) of property, plant and equipment	5, 10	169.6	(117.2)
Exploration and evaluation expenses and new ventures	5	(41.5)	(49.8)
Exploration costs written-off	5	(64.4)	(255.0)
Gain on disposal	5	12.1	-
General and administrative expenses		(121.3)	(102.5)
Operating profit	5	2,540.9	640.3
Finance income	6	279.1	48.8
Finance expenses	6	(358.2)	(374.6)
Profit before taxation		2,461.8	314.5
Income tax expense	7	(2,453.6)	(213.4)
Profit for the year		8.2	101.1
Profit for the year attributable to:			
Equity owners of the Company		8.2	101.1

Earnings per share	$ cents	$ cents
Basic	0.9	11.6
Diluted	0.9	11.6

Consolidated statement of comprehensive income

For the year ended 31 December

	2022	2021
	$ million	*$ million*
Profit for the year	8.2	101.1
Other comprehensive profit/(loss)		
Items that may be subsequently reclassified to income statement:		
Fair value gains/(losses) on cash flow hedges	269.1	(3,583.8)
Tax credit on cash flow hedges	1,005.6	1,433.2
Pension actuarial losses on long term employee benefit plans	(0.3)	-
Exchange differences on translation	(198.0)	(5.7)
Other comprehensive profit/(loss) for the period, net of tax	1,076.4	(2,156.3)
Total comprehensive profit/(loss) for the year	1,084.6	(2,055.2)
Total comprehensive profit/(loss) attributable to:		
Equity owners of the Company	1,084.6	(2,055.2)

Consolidated balance sheet

As at 31 December	Note	2022 $ million	2021 restated $ million
Assets			
Non-current assets			
Goodwill		1,327.1	1,327.1
Other intangible assets	9	880.0	873.7
Property, plant and equipment	10	5,690.2	7,246.7
Right-of-use assets	11	734.7	551.5
Deferred tax assets	7	1,406.5	1,938.4
Other receivables		298.0	263.0
Other financial assets	14	102.7	10.1
Total non-current assets		10,439.2	12,210.5
Current assets			
Inventories		142.9	211.4
Trade and other receivables		1,403.2	1,342.2
Other financial assets	14	80.8	41.8
Cash and cash equivalents		499.7	698.7
Total current assets		2,126.6	2,294.1
Total assets		12,565.8	14,504.6
Equity and liabilities			
Equity			
Share capital		171.1	171.1
Share premium		-	1,504.6
Other reserves		(606.2)	(1,276.8)
Retained earnings		1,456.4	74.6
Total equity		1,021.3	473.5
Non-current liabilities			
Borrowings	13	1,216.6	2,823.7
Provisions	12	3,933.7	5,022.6
Deferred tax	7	397.2	187.1
Trade and other payables		18.8	32.3
Lease creditor	11	603.8	489.2
Other financial liabilities	14	1,279.1	1,373.6
Total non-current liabilities		7,449.2	9,928.5
Current liabilities			
Trade and other payables		1,251.2	1,235.3
Borrowings	13	21.5	62.3
Lease creditor	11	220.8	165.1
Provisions	12	231.6	358.6
Current tax liabilities		198.7	116.8
Other financial liabilities	14	2,171.5	2,164.5
Total current liabilities		4,095.3	4,102.6
Total liabilities		11,544.5	14,031.1
Total equity and liabilities		12,565.8	14,504.6

Consolidated statement of changes in equity

For the year ended 31 December

	Share capital $ million	*Share premium(3) $ million*	*Merger reserve(3) $ million*	*Capital redemption reserve $ million*	*Cash flow hedge reserve (1) $ million*	*Costs of hedging reserve (1) $ million*	*Currency translation reserve $ million*	*Retained earnings $ million*	*Total equity $ million*
At 1 January 2022	**171.1**	**1,504.6**	**677.4**	**8.1**	**(2,062.1)**	**1.5**	**98.3**	**74.6**	**473.5**
Profit for the year	-	-	-	-	-	-	-	8.2	8.2
Other comprehensive income					1,286.1	(11.4)	(198.0)	(0.3)	1,076.4
Total comprehensive income	-	-	-	-	1,286.1	(11.4)	(198.0)	7.9	1,084.6
Purchase and cancellation of own shares	-	-	-	-	-	-	-	(360.6)	(360.6)
Share-based payments	-	-	-	-	-	-	-	36.9	36.9
Capital restructuring	-	(1,504.6)	(406.1)	-	-	-	-	1,910.7	-
Purchase of ESOP Trust Shares	-	-	-	-	-	-	-	(21.6)	(21.6)
Dividend paid	-	-	-	-	-	-	-	(191.5)	(191.5)
At 31 December 2022	**171.1**	**-**	**271.3**	**8.1**	**(776.0)**	**(9.9)**	**(99.7)**	**1,456.4**	**1,021.3**
At 1 January 2021	**0.1**	**910.0**	**-**	**-**	**80.2**	**9.8**	**104.0**	**(36.8)**	**1,067.3**
Profit for the period	-	-	-	-	-	-	-	101.1	101.1
Other comprehensive loss	-	-	-	-	(2,142.3)	(8.3)	(5.7)	-	(2,156.3)
Total comprehensive loss					(2,142.3)	(8.3)	(5.7)	101.1	(2,055.2)
Shares issued in settlement of D loan notes	-	134.7	-	-	-	-	-	-	134.7
Reverse takeover	171.0	(527.2)	635.9	8.1	-	-	-	-	287.8
Settlement of Premier's debt (2)	-	987.1	41.5	-	-	-	-	-	1,028.6
Share-based payments	-	-	-	-	-	-	-	13.4	13.4
Purchase of ESOP Trust Shares	-	-	-	-	-	-	-	(3.1)	(3.1)
At 31 December 2021	**171.1**	**1,504.6**	**677.4**	**8.1**	**(2,062.1)**	**1.5**	**98.3**	**74.6**	**473.5**

(1) Disclosed net of deferred tax

(2) Debt settlement relates to the issuance of shares in partial settlement of Premier's debt.

(3) Share premium and merger reserve balances recategorised to retained earnings following capital reduction effective 3 August 2022.

Consolidated statement of cash flows

For the year ended 31 December	Note	2022 $ million	2021 $ million
Net cash inflow from operating activities	15	3,129.8	1,614.2
Investing activities			
Expenditure on exploration and evaluation assets		(127.0)	(176.5)
Expenditure on property, plant and equipment	12	(476.5)	(437.4)
Expenditure on non-oil and gas intangible assets		(29.7)	(30.0)
Cash acquired on business combinations		-	97.4
Receipts for sub-lease income		10.4	7.4
Payments relating to disposal of oil and gas properties		(5.9)	-
Expenditure on business combinations – deferred consideration		(19.9)	(46.0)
Finance income received		20.0	14.1
Net cash outflow from investing activities		(628.6)	(571.0)
Financing activities			
Repurchase of shares		(360.6)	-
Proceeds from new borrowings – reserves based lending facility	13	-	1,617.5
Proceeds from new borrowings –bond	13	-	500.0
Proceeds from new borrowings – exploration financing facility	13	11.5	45.9
Lease liability payments	11	(254.0)	(160.4)
Repayment of short-term debt arising on business combination	13	-	(1,276.5)
Repayment of hedging liabilities arising on business combination		-	(48.5)
Repayment of reserves based lending facility	13	(1,662.5)	(697.5)
Repayment of junior debt	13	-	(400.0)
Repayment of exploration financing facility	13	(38.6)	(14.7)
Repayment of financing arrangement	13	(15.4)	(9.3)
Redemption of loan notes	13	-	(135.7)
Purchase of ESOP Trust shares		(21.6)	(3.1)
Interest paid and bank charges		(142.0)	(204.9)
Dividends paid	16	(191.5)	-
Net cash outflow from financing activities		(2,674.7)	(787.2)
Net (decrease)/increase in cash and cash equivalents		(173.5)	256.0
Net foreign exchange difference		(25.5)	(2.7)
Cash and cash equivalents at 1 January		698.7	445.4
Cash and cash equivalents at 31 December		499.7	698.7

Notes to the financial statements

1. Corporate information

Harbour Energy plc ('Harbour') is a limited liability company incorporated in Scotland and listed on the London Stock Exchange. The address of the registered office is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh, EH1 2EN, United Kingdom.

The consolidated financial statements of Harbour Energy plc ('the Company') and all its subsidiaries ('the Group') for the year ended 31 December 2022 were authorised for issue by the Board of Directors on 8 March 2023.

The Group's principal activities are the acquisition, exploration, development and production of oil and gas reserves on the UK and Norwegian continental shelves, Indonesia, Vietnam and Mexico.

2. Significant accounting policies

Basis of preparation

The consolidated financial statements have been prepared on a going concern basis in accordance with UK-adopted International Accounting Standards (IAS) in conformity with the requirements of the Companies Act 2006. The analysis used by the Directors in adopting the going concern basis considers the various plans and commitments of the Group as well as various sensitivity and reverse stress test analyses. The results from the downside sensitivities with regard to production and commodity price assumptions, which in management's view reflect two of the principal risks, indicate that material changes within one year that would impact the going concern basis of preparation are unlikely. Further details are within the Financial Review.

The presentation currency of the Group financial information is US dollars and all values in the Group financial information are presented in millions ($ million) and all values are rounded to the nearest 0.1 million, except where otherwise stated.

The financial statements have been prepared on the historical cost basis, except for certain financial assets and liabilities, including derivative financial instruments, which have been measured at fair value.

In October 2020, Harbour Energy Limited entered into an agreement with Premier Oil plc ('Premier') regarding an all-share merger between Premier and Harbour Energy Limited's subsidiary, Chrysaor Holdings Limited ('Chrysaor'). Under the terms of the merger, Premier legally acquired Chrysaor through the issuance of consideration shares whilst Chrysaor was the acquiror for accounting purposes, primarily as a result of its ability to appoint the Board of the enlarged group. The transaction completed on 31 March 2021, whereupon Premier, being the legal acquirer and accounting acquiree, changed its name from Premier Oil plc to Harbour Energy plc.

The consolidated financial statements provide comparative period information with respect to the prior year but this only includes nine months of Premier contribution compared to a full 12 months contribution for the year ended 31 December 2022. The financial information for the year ended 31 December 2022 does not constitute statutory accounts as defined in sections 435 (1) and (2) of the Companies Act 2006. Statutory accounts for the year ended 31 December 2021 have been delivered to the Registrar of Companies and those for 2022 will be delivered following the Company's annual general meeting. The auditor has reported on these accounts; their report was unqualified. Their report did not include a reference to any other matters to which the auditor drew attention by way of emphasis of matter and did not contain a statement under section 498 (2) or (3) of the Companies Act 2006.

This preliminary announcement is consistent with the audited financial statements of the Group for the year-ended 31 December 2022. It is anticipated that the full Annual Report and Financial Statements will be published on the Company's website during March 2022 (www.harbourenergy.com). It is anticipated that the Annual General Meeting will be held on 10 May 2023.

Accounting Policies

The accounting policies adopted in the preparation of the 2022 consolidated financial statements are consistent with those adopted and disclosed in Harbour's 2021 Annual Report and Accounts. A number of amendments to existing standards and interpretations were effective from 1 January 2022 but had no impact on the half-year financial statements. The Group has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Basis of consolidation

The consolidated financial statements comprise the financial statements of the Company and its subsidiaries as at 31 December 2022. Subsidiaries are those entities over which the Group has control. Control is achieved where the Group has the power over the subsidiary, has rights, or is exposed to variable returns from the subsidiary and has the ability to use its power to affect its returns. All subsidiaries are 100 per cent owned by the Group and there are no non-controlling interests.

If the Group loses control over a subsidiary, it derecognises the related assets (including goodwill), liabilities, non-controlling interest and other components of equity, while any resultant gain or loss is recognised in profit or loss. Any investment retained is recognised at fair value.

The results of subsidiaries acquired or disposed of during the year are included in the income statement from the effective date of acquisition or up to the effective date of disposal, as appropriate. Where necessary, adjustments are made to the financial statements of subsidiaries acquired to bring the accounting policies used into line with those used by other members of the Group.

All intra-group transactions and balances have been eliminated on consolidation.

Prior Year Adjustment

Other financial liabilities – commodity derivatives within current liabilities as at 31 December 2021 included a number of financial instruments which had matured on the last day of the financial year for which the related liability should have been classified within trade and other payables. The relevant amounts have therefore been reclassified to trade and other payables which is also held within current liabilities. There was no impact on any of the other primary statements. Each of the affected financial statement line items has been restated and the impact is summarised in the following table.

Balance sheet at 31 December 2021	As previously reported $ million	Adjustments $ million	As restated $ million
Other financial liabilities - commodity derivatives (note 14)	(2,526.2)	361.7	(2,164.5)
Trade and other payables	(873.6)	(361.7)	(1,235.3)

Use of judgements and estimates

In preparing these financial statements, management has made judgements and estimates that affect the application of accounting policies and the reported amounts of assets and liabilities, income and expenses. Actual results may differ from these estimates. The significant judgements made by management in applying the Group's accounting policies, and the key sources of estimation uncertainty, were the same as those described in Harbour's 2021 Annual Report and Accounts. Disclosure regarding the judgements and estimates made in assessing the impact of climate change and the energy transition are detailed below.

Impact of climate change on the financial statements and related disclosures

Judgements and estimates made in assessing the impact of climate change and the energy transition

Harbour monitors global climate change and energy transition developments and plans accordingly. Management recognises there is a general high level of uncertainty about the speed and scale of impacts which, together with limited historical information, provides significant challenges in the preparation of forecasts and plans with a range of possible future scenarios.

The Group's strategic ambition is to achieve Net Zero by 2035 through several opportunities, including operational improvements, UK offshore electrification, UK carbon capture and storage (CCS) and the eventual cessation of production of mature fields. Where the Group cannot reduce its Scope 1 and 2 emissions, it will invest in carbon offsets to achieve the goal of net zero. All new economic investment decisions include the cost of carbon, and opportunities are assessed on their climate-impact potential and alignment with Harbour Energy's Net Zero goal, taking into consideration both GHG volumes and intensity. The corporate modelling that supports the preparation of the financial statements (such as asset impairment assessment, going concern and viability, deferred tax recoverability) includes project costs related to carbon, capture and storage; and certain limited electrification and reduction of Scope 1 and 2 GHG emissions initiatives. Emissions reduction incentives are part of staff remuneration and annual bonus schemes. Additionally, the cost of borrowing is tied to our gross operated CO_2 emissions performance, with GHG metrics being linked to our RBL interest expense, further incentivising our emissions reduction targets.

As a result, climate change and the energy transition have the potential to significantly impact the accounting estimates adopted by management and therefore the valuation of assets and liabilities reported on the balance sheet. On an ongoing basis management continues to assess the potential impacts on the significant judgements and estimates used in the financial statements. Estimates adopted in the preparation of the financial statements reflect management's best estimate of future market conditions where, in particular, commodity prices can be volatile. Notwithstanding the challenges around climate change and the energy transition, it is management's view that the financial statements are consistent with the disclosures in the Strategic report.

This note provides insight into how Harbour has considered the impact on valuations of key line items in the financial statements and how they could change based on the climate change scenarios and sensitivities considered. The scenarios presented show what the possible impact could be on the financial statements considering both high and low-price curve outlooks. Importantly, these climate change scenarios do not form the basis of the preparation of the financial statements but rather indicate how the key assumptions that underpin the financial statements would be impacted by the climate change scenarios. It is recognised that the reality of the nature of progress of energy transition will bring greater levels of disruption and volatility than these external scenarios expect and do not represent management's current best estimate.

Management's current best estimate , which was derived from consideration of a range of considered economic forecast, has been used on the same basis to prepare the financial statements and is represented by the *Harbour scenario* oil price curve. Management continues to review these estimates and assumptions to ensure they reflect the latest economic environment conditions and market information available.

Impairment of property, plant and equipment, and goodwill

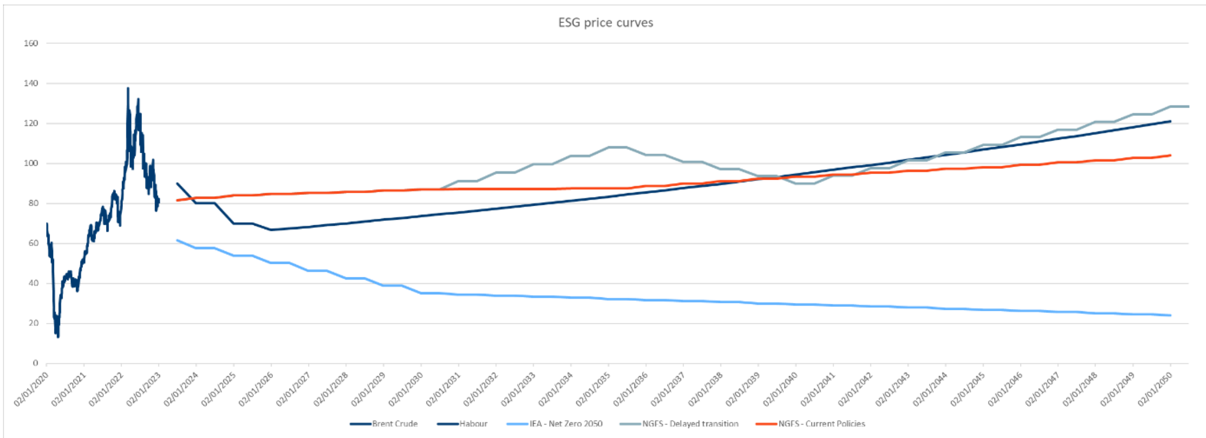
The energy transition has the potential to significantly impact future commodity and carbon prices which would, in turn, affect the recoverable amount of property, plant and equipment and goodwill. In the current period, the *Harbour scenario* real long-term commodity price assumptions, when testing for impairment, were $65/bbl (2021: $65/bbl) and 65p/therm (2021: 60p/therm) for Brent crude and UK NBP gas, respectively. The real long-term price assumptions for the UK regulatory price of carbon are £80 /tonne, being $100/tonne at $:£1.25 foreign exchange rate, (2021: £55/$74/tonne) and voluntary offsets $25/tonne used, with sensitivities run at $100/tonne (2021: $100/tonne). Sensitivity analysis using a carbon price of $100/tonne indicates that material impairments would not arise. Such assumptions are inherently uncertain and may ultimately differ from the actual amounts.

During 2022 there was a net pre-tax impairment credit of $170 million comprising: impairment on a single CGU asset $163 million, impairments reversals on North Sea assets $250 million and decommissioning provision reductions $83 million. In 2021, certain impairments were recognised as a result of underlying reservoir performance.

Sensitivities on the impairment of property, plant and equipment and goodwill have been prepared using various price scenarios to show the possible impact on net book carrying values. As noted, the *Harbour scenario* is the basis for the preparation of the financial statements and impairments sensitivities have been prepared at an average -10 per cent and +10 per cent to the *Harbour scenario* average crude and selected published climate change price curves. Sensitivity analysis on carbon price $100/tonne indicates that impairments would not have a material impact on the financial statements.

The sensitivity scenarios described below are price curves only and the modelling assumes that all other factors remain unchanged from the *Harbour scenario* used for the basis of preparation of the financial statements. These sensitivities are stated before any management mitigation actions to manage downside risks if the scenarios were to occur.

- Harbour scenario — base price curve for crude oil used for impairment testing
- NGFS Current Policies — reflects high physical risks and low transition risks
- NGFS Delayed Transition — reflects low physical risks and high transition risks
- IEA Net Zero 2050 — reflects low physical risks and low transition risks



The graph above shows the crude oil price curves for the period to 2050 for the *Harbour scenario*, NGFS Current Policies, NGFS Delayed Transition and IEA Net Zero 2050. There are no climate change price curves published by NGFS or the IEA for UK NBP gas. All the scenario price curves are dependent on factors covering supply, demand, economic and geopolitical events and therefore are inherently uncertain and subject to significant volatility and hence unlikely to reflect the future outcome.

The results of the sensitivities are as follows and show the impact on the balance sheet carrying values.

$ million	Carrying value	Crude oil				
		-10% to *Harbour scenario*	+10% to Harbour scenario	NGFS Current Policies	NGFS Delayed Transition	IEA Net Zero 2050
Property, plant and equipment	5,690	(57)	-	-	-	(355)
Goodwill	1,327	-	-	-	-	-

The sensitivity results show that under the -10 per cent to Harbour scenario (oil and gas commodity prices reduced from 1 January 2023) an impairment of $57 million would arise on a single North Sea CGU. The +10 per cent to Harbour scenario (oil and gas commodity prices increased from 1 January 2023), NGFS Current and Delayed scenarios show no incremental impairments as these scenarios are all favourable to the Harbour scenario. Furthermore, under these three scenarios, no reversal of any historic impairment is triggered as there have been no prior crude oil-price related impairments. Under the IEA Net Zero 2050 scenario there would be an impairment in property, plant and equipment of $355 million with goodwill not impacted given sufficient value headroom.

Property, plant and equipment – depreciation and expected useful lives

The energy transition has the potential to reduce the expected useful lives of assets and consequently accelerate depreciation charges. There are no significant judgements and/or critical estimation uncertainty related to climate factors.

Intangible assets – exploration and evaluation assets

The energy transition has the potential to affect the future development or viability of exploration and evaluation prospects. A significant portion of the Group's exploration and evaluation assets relate to prospects that could be tied back to existing infrastructure and hence require less capital investment as these assets are less exposed to the impacts of the energy transition compared to large frontier developments. At each balance sheet date, all exploration and evaluation prospects are reviewed against the Group's financial framework to ensure that the continuation of activities is planned and expected. There are no significant judgements and/or critical estimation uncertainty related to climate factors.

Decommissioning cost and provisions

The energy transition may accelerate the decommissioning of assets which would result in an increase in the carrying value of associated decommissioning provisions. Whilst the Group currently expects to incur decommissioning costs over the next 40 years, we anticipate the majority of costs will be incurred between the next 10 to 20 years which will reduce the exposure to the impact of the energy transition. Decommissioning cost estimates are based on the known regulatory and external environment. These cost estimates and recoverability of associated deferred tax may change in the future, including as a result of the energy transition.

On the basis that all other assumptions in the calculation remain the same, a 10 per cent increase in the cost estimates, and a 10 per cent reduction in the applied discount rates used to assess the final decommissioning obligation, would result in increases to the decommissioning provision of approximately $417 million and $162 million, respectively. This change would be principally offset by a change to the value of the associated asset unless the asset is fully depreciated, in which case the change in estimate is recognised directly within the income statement.

The energy transition may accelerate the decommissioning of producing assets and therefore increase the carrying value of provisions. The Group currently expects to incur decommissioning costs over the next 40 years, the majority of which are anticipated to be incurred between the next 10 to 20 years. Currently, the timing of decommissioning expenditures have not been materially brought forward and management do not consider that any reasonable change in the timing of decommissioning expenditure will have a material impact on the decommissioning provisions.

3. Segment information

The chief operating decision maker, who is responsible for allocating resources and assessing performance of the Group's business segments, has been identified as the Chief Executive Officer.

The Group's activities consist of one class of business being the acquisition, exploration, development and production of oil and gas reserves and related activities, and are split geographically and managed in two regions, namely 'North Sea' and 'International'. The North Sea segment includes the UK and Norwegian continental shelves, and the 'International' segment includes Indonesia, Vietnam and Mexico.

Information on major customers can be found in note 4.

Income statement	***2022***	***2021***
	$ million	***$ million***
Revenue		
North Sea	5,082.1	3,268.2
International	307.9	210.6
Total Group sales revenue	5,390.0	3,478.8
Other income		
North Sea	40.9	139.0
International	0.3	0.2
Total Group revenue and other income	5,431.2	3,618.0
Operating profit		
North Sea	2,388.4	699.3
International	152.5	(59.0)
Group operating profit	2,540.9	640.3
Finance income	279.1	48.8
Finance expenses	(358.2)	(374.6)
Profit before income tax	2,461.8	314.5
Income tax expense	(2,453.6)	(213.4)
Profit for the financial year	8.2	101.1

Balance sheet

Segment assets		
North Sea	11,346.2	13,325.8
International	1,219.6	1,178.8
Total assets	12,565.8	14,504.6
Segment liabilities		
North Sea	(10,937.3)	(13,379.6)
International	(607.2)	(651.5)
Total liabilities	(11,544.5)	(14,031.1)

Other information

Capital additions		
North Sea	576.2	640.7
International	108.6	68.4
Total capital additions	684.8	709.1

Depreciation, depletion and amortisation		
North Sea	1,470.4	1,299.8
International	75.4	71.2
Total depreciation, depletion and amortisation	1,545.8	1,371.0
Exploration and evaluation expenses and new ventures		
North Sea	33.5	45.4
International	8.0	4.4
Total exploration and evaluation expenses and new ventures	41.5	49.8
Exploration costs written-off		
North Sea	71.6	121.1
International	(7.2)	133.9
Total exploration costs written-off	64.4	255.0

Exploration costs written-off of $64.4 million is net of a $5.7 million credit related to a decrease in the decommissioning provisions in the North Sea (note 12) and includes a $7.0 million credit related to a change to the decommissioning estimate in the Falkland Islands business unit (2021: $6.3 million relating to the effect of changes in decommissioning provisions on oil and gas intangible assets previously written-off).

4. Revenue from contracts with customers and other income

	2022	***2021***
	$ million	***$ million***
Type of goods		
Crude oil sales	2,791.9	2,023.4
Gas sales	2,321.5	1,264.0
Condensate sales	238.3	163.6
Total revenue from contracts with customers (1)	5,351.7	3,451.0
Tariff income	30.0	27.2
Other revenue	8.3	0.6
Total revenue from production activities	5,390.0	3,478.8
Other income (2)	41.2	139.2
Total revenue and other income	5,431.2	3,618.0

(1) Revenues from contracts with customers of $8,536.5 million (2021: $4,968.2 million) include crude oil sales of $3,544.7 million (2021: $2,278.1 million) and gas sales of $4,753.5 million (2021: $2,526.5 million). This was prior to realised hedging losses in the period of $752.8 million (2021: $254.7 million) on crude oil and $2,432.0 million (2021: $1,262.5 million) on gas sales.

(2) Other income mainly represents $20.3 million partner recoveries related to lease obligations (2021: $26.0 million), mark to market losses on EUA emissions hedges of $2.6 million (2021: gain of $51.0 million) and $16.7 million in respect of Research and Development Expenditure credits (2021: $17.5 million). Other income in 2021 included a receipt from ConocoPhillips in relation to an adjustment to consideration relating to Chrysaor's purchase of the ConocoPhillips UK business in 2019 (2021: $40.0 million).

Approximately 84 per cent (2021: 84 per cent) of the revenues were attributable to sales to energy trading companies of the Shell group.

5. Operating profit

	2022 $ million	2021 $ million
Cost of operations		
Production, insurance and transportation costs	1,114.2	1,085.5
Gas purchases	36.6	28.4
Royalties	5.0	3.8
Depreciation of oil and gas assets (note 10)	1,318.4	1,204.1
Depreciation of right-of-use oil and gas assets (note 11)	218.6	153.9
Capitalisation of IFRS 16 lease depreciation on oil and gas assets (note 11)	(29.9)	(30.7)
Other cost of operations	-	(0.5)
Onerous contract provision (note 12)	-	(2.3)
Amortisation of capacity rights (note 9)	1.0	1.6
Remeasurement of royalty valuation	-	(0.5)
Remeasurement – loss on termination of lease	-	0.3
Movement in over/underlift balances and hydrocarbon inventories	180.9	9.6
Total cost of operations	2,844.8	2,453.2
Impairment (reversal)/expense of property, plant and equipment (note 10)	(87.3)	108.7
Impairment (gain)/loss due to (decrease)/increase in decommissioning provisions on oil and gas tangible assets (note 12)	(82.3)	8.5
Exploration costs written-off (note 9) (1)	64.4	255.0
Exploration and evaluation expenditure and new ventures (2)	41.5	49.8
(Gain)/loss on disposal (3)	(12.1)	0.1
General and administrative expenses		
Depreciation of right-of-use non-oil and gas assets (note 11)	11.2	10.5
Depreciation of non-oil and gas assets (note 10)	5.4	5.5
Amortisation of non-oil and gas intangible assets (note 9)	21.1	26.1
Other administrative costs	83.6	60.4
Total general and administrative expenses	121.3	102.5
Auditors' remuneration		
Audit fees		
Fees payable to the Company's auditor for the Company's Annual Report	2.6	3.1
Audit of the Company's subsidiaries pursuant to legislation	0.6	0.5
Non audit fees (5)		
Other services pursuant to legislation – interim review	0.2	0.3
Other services (6)	0.8	0.4

5. Operating profit (continued)

(1) Exploration costs written-off of $64.4 million includes a credit of $7.0 million related to a change to the decommissioning estimate in the Falkland Islands business unit.

(2) Exploration and evaluation expenditure and new ventures of $41.5 million (2021: $49.8 million) includes $28.4 million (2021: $14.4 million) of early project costs on new ventures incurred in respect of the Group's interest in CCS and electrification projects in the UK, plus $13.1 million (2021 $35.4 million) of ongoing pre-licence costs.

(3) The gain on disposal of $12.1 million relates to the release of a provision associated with Premier's sale of its legacy Pakistan assets in 2019 after the expiry of the deadline in the period for tax claims to be submitted.

(4) Expenses related to both short-term and low value lease arrangements are considered to be immaterial for reporting purposes.

(5) The Company has a policy on the provision of non-audit services by the auditor which is aimed at ensuring their continued independence. This policy is available on the Group's website. The use of the external auditor for services relating to accounting systems or financial statement preparations is not permitted, as are various other services that could give rise to conflicts of interest or other threats to the auditor's objectivity that cannot be reduced to an acceptable level by applying safeguards.

(6) Other services in 2022 primarily relate to reporting accountant services provided by EY. In 2021 this also included services in respect of the merger or other corporate transactions. The Audit and Risk Committee concluded that shareholder value was best served by appointing our auditors for this work.

6. Finance income and finance expenses

	2022 $ million	2021 $ million
Finance income		
Bank interest	10.2	0.9
Other interest and finance gains[(1)]	20.0	3.2
IFRS 9 modification impact	-	13.9
Lease finance income	1.7	3.2
Finance income on deferred revenue	-	1.2
Realised gains on interest rate swaps	6.5	-
Realised gains on foreign exchange forward contracts	0.5	10.0
Gains on derivatives [(2)]	38.2	14.5
Foreign exchange gains [(3)]	202.0	1.9
Total finance income	279.1	48.8
Finance expenses		
Interest payable on reserves based lending	71.1	101.6
Interest payable on bond	27.3	5.7
Interest payable on loan notes	-	5.6
Other interest and finance expenses[(4)]	11.7	16.6
Lease interest (note 11)	25.1	22.3
Realised losses on interest rate swaps	-	2.4
Losses on derivatives [(5)]	48.0	14.6
Finance expense on deferred revenue	19.9	-
Foreign exchange losses	-	65.2
Bank and financing fees [(6)]	91.0	63.4
Unwinding of discount on decommissioning and other provisions (note 12)	65.1	78.0
	359.2	375.4
Finance costs capitalised during the year [(7)]	(1.0)	(0.8)
Total finance expense	358.2	374.6

(1) Other interest and finance gains includes $16.0 million (2021: $1.9 million) related to an update to the amount recognised under the decommissioning liability agreement.

(2) Gains on derivatives mainly relates to mark to market gains on interest rate and foreign currency derivatives.

(3) Significant unrealised foreign exchange gains which consist mainly of unrealised gains arising from revaluation of open gas hedges denominated in pound sterling.

(4) Other interest includes an $9.5 million charge (2021: $11.6 million) which represents interest under a financing arrangement (note 13).

(5) Losses on derivatives relate to changes in the fair value of an embedded derivative within one of the Group's gas contracts (2021: $14.6 million).

(6) Bank and financing fees include an amount of $54.9 million (2021: $38.9 million) relating to the amortisation of arrangement fees and related costs capitalised against the Group's long-term borrowings (note 13).

(7) The amount of finance costs capitalised was determined by applying the weighted average rate of finance costs applicable to the borrowings of the Group of 4.4 per cent to the expenditures on the qualifying assets (2021: 3.7 per cent).

7. Income tax

The major components of income tax expense for the years ended 31 December 2022 and 2021 are:

	2022 $ million	2021 $ million
Current income tax expense		
UK corporation tax	671.7	202.2
Overseas tax	53.5	(5.2)
Adjustments in respect of prior years	(19.4)	(4.9)
Total current income tax expense	705.8	192.1
Deferred tax expense		
UK corporation tax	302.1	7.7
UK Energy Profits Levy	1,469.5	-
Overseas tax	(7.5)	(10.3)
Adjustments in respect of prior years	(16.3)	23.9
Total deferred tax expense	1,747.8	21.3
Total tax expense reported in the income statement	2,453.6	213.4
The tax credit in the statement of comprehensive income is as follows:		
Tax credit on cash flow hedges	(1,005.6)	(1,433.2)

Reconciliation of tax expense and the accounting profit before taxation multiplied by the statutory rate of corporation tax and supplementary charge applying to UK oil and gas production operations for the years ended 31 December 2022 and 2021 is, as follows:

	2022 $ million	2021 $ million
Profit before income tax	2,461.8	314.5
At the Group's statutory income tax rate of 55.0% (2021: 40.0%)	1,354.0	125.8
Effects of:		
Expenses/ (income) not deductible/ (taxable) for tax purposes	(11.7)	56.8
Interest not deductible for supplementary charge and Energy Profits Levy	53.1	13.1
Adjustments in respect of prior years	(35.8)	19.0
Movement in unrecognised deferred tax assets	(72.2)	27.4
Deferred Energy Profits Levy	1,469.2	-
Impact of different tax rates	(190.3)	4.0
Expenses not deductible for Energy Profits Levy	8.0	-
Energy Profits Levy investment allowance	(81.4)	-
Investment allowance	(39.3)	(32.7)
Total tax expense reported in the consolidated income statement at the effective tax rate of 100% (2021: 68%)	2,453.6	213.4

The effective tax rate for the year was 100 per cent, compared to 68 per cent for 2021.

The tax expense/(credit) reconciliation has been prepared based on the statutory rate of taxation applying to UK oil and gas production because the majority of Group profit was generated on the UK continental shelf. UK oil and gas production is taxed at a rate of 30% (2021: 30%), a supplementary charge of 10% (2021: 10%), and with effect from 26 May 2022, the Energy Profits Levy (EPL) of 25% to give an overall tax rate of 65% (2021: 40%). As the EPL was introduced part way through the financial year a blended average rate of 55% has been applied.

The future effective tax rate is impacted by the mix of jurisdictions in which the Group operates. The UK statutory tax rate for oil and gas production operations is expected to remain a primary influence on the effective tax rate. The EPL will increase to a rate of 35% from 25% with effect from 1 January 2023 and consequently the headline rate will increase next year to 75%. The Energy Profits Levy at the 35% rate will be in place until 31 March 2028.

Deferred tax

The principal components of deferred tax are set out in the following tables:

	2022 $ million	***2021 $ million***
Deferred tax assets	1,406.5	1,938.4
Deferred tax liabilities	(397.2)	(187.1)
Total deferred tax	1,009.3	1,751.3

The origination of and reversal of temporary differences are, as shown in the next table, related primarily to movements in the carrying amounts and tax base values of expenditure and the timing of when these items are charged and/or credited against accounting and taxable profit.

7. Income tax (continued)

Deferred tax (continued)

	Accelerated capital allowances $ million	*Decommissioning $ million*	*Losses $ million*	*Fair value of derivatives $ million*	*Other $ million*	*Overseas $ million*	*Total $ million*
As at 1 January 2021	(2,650.5)	1,640.7	-	(57.1)	51.5	(16.0)	(1,031.4)
Deferred tax expense	385.9	(178.2)	(216.1)	3.6	(26.8)	10.3	(21.3)
Comprehensive income	-	-	-	1,433.2	-	-	1,433.2
Foreign exchange	13.5	(13.6)	-	4.0	(1.1)	1.9	4.7
Additions from business combinations and joint arrangements	(569.0)	564.0	1,530.6	8.4	15.2	(183.1)	1,366.1
As at 31 December 2021	***(2,820.1)***	***2,012.9***	***1,314.5***	***1,392.1***	***38.8***	***(186.9)***	***1,751.3***
Deferred tax expense	(657.7)	(361.7)	(745.2)	49.0	(39.7)	7.5	(1,747.8)
Comprehensive income	-	-	-	1,005.6			1,005.6
Foreign exchange	82.2	(85.9)	(0.2)	5.0	(1.8)	0.9	0.2
As at 31 December 2022	(3,395.6)	1,565.3	569.1	2,451.7	(2.7)	(178.5)	1,009.3

7. Income tax (continued)

The Group's deferred tax assets as at 31 December 2022 are recognised to the extent that taxable profits are expected to arise against which the tax assets can be utilised. The Group assessed the recoverability of its UK ring fenced losses and allowances using corporate assumptions which are consistent with the Group's impairment assessment. Based on those assumptions, the Group expects to fully utilise its recognised UK tax losses and allowances. The recovery of the Group's UK decommissioning deferred tax asset is additionally supported by the ability to carry back decommissioning tax losses and set these against ring fence taxable profits of prior periods.

The EPL will increase to a rate of 35% from 25% with effect from 1 January 2023. The increase in rate was substantively enacted on 30 November 2022. The EPL will be in place until 31 March 2028. Any temporary differences subject to the EPL expected to reverse in this period have consequently been remeasured to the higher rate. This has resulted in a one-off deferred tax charge to the income statement of $1,469.2 million and a one-off deferred tax credit arising on unrealised derivative balances in Other Comprehensive Income of $1,005.5 million. The net impact on the deferred tax asset at the end of the period as a result of the EPL is a decrease in the deferred tax asset of $463.7 million.

In line with other sensitivity analysis undertaken, we have assessed the impact on the recoverability of deferred tax assets based on an average -10 per cent to the Harbour scenario average crude price curves. The sensitivity analysis indicates that there would no material impact to the recoverability of deferred tax assets.

The Group has unrecognised UK tax losses and allowances as at 31 December 2022 of approximately $201.7 million (2021: $343.1 million) in respect of ring fence losses, $111.1 million (2021: $104.4 million) in respect of ring fence investment allowance and $807.2 million (2021: $741.5 million) in respect of non-ring fence losses.

The Group also has unrecognised tax losses of approximately $156.9 million (2021: $212.8 million) in respect of its international operations. These losses include amounts of $30.3 million which will expire, primarily within 5 years and $13.8 million expiring within 10 years.

The overseas deferred tax relates mainly to temporary differences associated with fixed asset balances.

No deferred tax liabilities have been provided on unremitted earnings of overseas subsidiaries, because due to the application of withholding reliefs under international double taxation treaties and dividend exemptions under UK and Netherlands legislation no additional taxation is expected to arise on future distribution.

Legislation was introduced in UK Finance Act 2021 to increase the main rate of UK corporation tax for non-ring fence profits from 19 per cent to 25 per cent from 1 April 2023. This change does not have a material impact on the Group as the UK profits are primarily subject to the UK ring fence tax rate.

8. Earnings per share (EPS)

Basic EPS is calculated by dividing the profit after tax attributable to ordinary shareholders of the Group by the weighted average number of ordinary shares in issue during the year.

Diluted EPS is calculated by dividing the profit after tax attributable to ordinary shareholders by the weighted average number of ordinary share in issue during the year plus the weighted average number of ordinary shares that would be issued on conversion of all the dilutive potential ordinary shares into ordinary shares.

The following table reflects the income and share data used in the basic and diluted EPS calculations:

	2022 million	***2021 million***
Earnings for the year ($ millions)		
Earnings for the purpose of basic earnings per share	8.2	101.1
Effect of dilutive potential ordinary shares	-	-
Earnings for the purpose of diluted earnings per share	8.2	101.1
Number of ordinary shares (millions)		
Weighted average number of ordinary shares for the purpose of basic earnings per share (1)	899.8	871.2
Dilutive potential ordinary shares (2)	12.3	1.3
Weighted average number of ordinary shares for the purpose of diluted earnings per share	912.1	872.5
Earnings per share ($ cents)		
Basic	0.9	11.6
Diluted	0.9	11.6

(1) During the current period 78.4 million ordinary shares were repurchased as part of the share buyback programme.

(2) Excludes certain share options outstanding at 31 December 2022 as their option price was greater than market price.

9. Other intangible assets

Cost	*Oil and gas assets $ million*	*Non-oil and gas assets (3) $ million*	*Capacity rights (4) $ million*	*Total $ million*
At 1 January 2021	391.3	94.9	10.3	496.5
Additions during the year	210.0	30.2	-	240.2
Additions from business combinations and joint arrangements	596.7	0.4	-	597.1
Transfers to property, plant and equipment	(139.5)	-	-	(139.5)
Increase in decommissioning asset (note 12)	10.4	-	-	10.4
Prior capitalised costs expensed	-	(4.7)	-	(4.7)
Unsuccessful exploration written-off	(255.0)	-	-	(255.0)
Currency translation adjustment	(0.5)	(1.4)	(0.1)	(2.0)
At 31 December 2021	**813.4**	**119.4**	**10.2**	**943.0**
Additions during the year	111.0	30.7	-	141.7
Transfers to property, plant and equipment	(29.0)	-	-	(29.0)
Decrease in decommissioning asset (note 12) (1)	(11.8)	-	-	(11.8)
Unsuccessful exploration written-off (2)	(64.4)	-	-	(64.4)
Currency translation adjustment	(2.5)	(12.5)	(1.4)	(16.4)
At 31 December 2022	**816.7**	**137.6**	**8.8**	**963.1**
Amortisation				
At 1 January 2021	-	34.8	7.6	42.4
Charge for the year	-	26.1	1.6	27.7
Currency translation adjustment	-	(0.7)	(0.1)	(0.8)
At 31 December 2021	**-**	**60.2**	**9.1**	**69.3**
Charge for the year	-	21.1	1.0	22.1
Currency translation adjustment	-	(7.0)	(1.3)	(8.3)
At 31 December 2022	**-**	**74.3**	**8.8**	**83.1**
Net book value				
At 31 December 2021	813.4	59.2	1.1	873.7
At 31 December 2022	816.7	63.3	-	880.0

(1) A decrease to decommissioning assets of $11.8 million (2021: increase of $10.4 million) was made during the year as a result of an update to decommissioning estimates (note 12).

(2) The exploration write-off of $64.4 million (2021: $255.0 million), which relates to costs associated with licence relinquishments and uncommercial well evaluations, is net of a $5.7 million credit related to a decrease in decommissioning provisions in the North Sea (note 12) and a $7.0 million credit related to a change to the decommissioning estimate in the Falkland Islands business unit (2021: $6.3 million relating to the effect of changes in decommissioning provisions on oil and gas intangible assets previously written-off).

(3) Non-oil and gas assets relate primarily to Group IT software.

(4) The capacity rights represent National Transmission System (NTS) entry capacity at Bacton and Teesside acquired as part of the business combination completed in 2017. These rights, which have been amortised on a contracted volume basis, are now fully amortised.

10. Property, plant and equipment

Cost	Oil and gas assets $ million	Fixtures and fittings & office equipment $ million	Total $ million
At 1 January 2021	9,996.0	22.8	10,018.8
Additions during the year	464.5	4.4	468.9
Additions from business combinations and joint arrangements	1,814.3	4.2	1,818.5
Transfers from intangible assets	139.5	-	139.5
Disposals	-	(0.3)	(0.3)
Decrease in decommissioning asset (note 12)	(357.8)	-	(357.8)
Currency translation adjustment	(34.5)	(0.3)	(34.8)
At 31 December 2021	**12,022.0**	**30.8**	**12,052.8**
Additions (1)	532.4	10.7	543.1
Transfers from intangible assets	29.0	-	29.0
Decrease in decommissioning asset (note 12) (2)	(778.8)	-	(778.8)
Currency translation adjustment	(369.0)	(3.2)	(372.2)
At 31 December 2022	**11,435.6**	**38.3**	**11,473.9**
Accumulated depreciation			
At 1 January 2021	3,480.2	16.2	3,496.4
Charge for the year	1,204.1	5.5	1,209.6
Impairment	117.2	-	117.2
Disposals	-	(0.1)	(0.1)
Currency translation adjustment	(16.6)	(0.4)	(17.0)
At 31 December 2021	4,784.9	21.2	4,806.1
Charge for the year	1,318.4	5.4	1,323.8
Net impairment reversal (3)	(169.6)	-	(169.6)
Currency translation adjustment	(174.4)	(2.2)	(176.6)
At 31 December 2022	**5,759.3**	**24.4**	**5,783.7**
Net book value:			
At 31 December 2021	7,237.1	9.6	7,246.7
At 31 December 2022	5,676.3	13.9	5,690.2

Included within property, plant and equipment additions of $543.1 million (2021: $468.9 million) are associated cash flows of $476.5 million (2021: $437.4 million) and non-cash flow movements of $66.6 million (2021: ($31.5 million)), represented by a $44.2 million increase in capital accruals (2021: $9.0 million increase) and $22.4 million of capitalised lease depreciation (2021: $22.5 million).

A decrease in the decommissioning assets of $778.8 million (2021: $357.8 million) was made during the year as a result of both new obligations and an update to the decommissioning estimates (note 12).

During the year, the Group recognised a net pre-tax impairment credit of $169.6 million (post-tax $49.8 million) (2021: impairment charge of $117.2 million; post-tax $70.3 million) comprising a pre-tax impairment reversal of $250.5 million (2021: $ nil) and a pre-tax impairment credit of $82.3 million (2021: $8.5 million charge) in respect of revisions to decommissioning estimates on the Group's non-producing assets with no remaining net book value (see note 12). This is net of a pre-tax impairment charge representing a write-down of property, plant and equipment assets of $163.2 million (2021: $108.7 million).

The impairment reversal was driven by a higher forward curve and long term price assumption for gas resulting in reversals of $250.5 million covering two cash generating groups in the North Sea business unit.

The impairment to property, plant and equipment of $163.2 million, arises primarily from a single CGU in the UK North Sea, driven primarily due to the contracted price realised for crude sales being negatively impacted by the pricing differential between Urals and Brent crude, which is currently subject to dispute with the buyer, and also a revised operating cost profile for the field. Impairments on property, plant and equipment are reversible in the future.

Key assumptions used in calculations

Assumptions used in impairment measurement include estimates of commercial reserves and production volumes, future oil and gas prices, discount rates and the level and timing of expenditures, all of which are inherently uncertain.

Commodity and carbon prices - The Group uses the fair value less cost of disposal method (FVLCD) to calculate the recoverable amount of the cash-generating units (CGU) consistent with a level 3 fair value measurement (see note 14). In determining the recoverable value, appropriate discounted-cash-flow valuation models were used, incorporating market-based assumptions. Management's commodity price curve assumptions are benchmarked against a range of external forward price curves on a regular basis. Individual field price differentials are then applied. The first three years reflect the market forward price curves transitioning to a long-term price from 2026, thereafter inflated at 2.5 per cent per annum. The long-term commodity prices used were $65 per barrel for crude and 65p per therm for gas.

Production volumes - Production volumes are based on life of field production profiles for each asset within the CGU. Proven and probable reserves are estimates of the amount of oil and gas that can be economically extracted from the Group's oil and gas assets. The Group estimates its reserves using standard recognised evaluation techniques, assessed at least annually by management. Proven and probable reserves are determined using estimates of oil and gas in place, recovery factors and future commodity prices.

Costs - Operating expenditure, capital expenditure and decommissioning costs are derived from the Group's business plan. The discount rate reflects management's estimate of the Group's country-based weighted average cost of capital (WACC). Foreign exchange rates are based on management's long-term rate assumptions, with reference to a range of underlying economic indicators.

Sensitivity to changes in assumptions used in calculations

Reductions or increases in the long-term oil and gas prices of 10 per cent are considered to be reasonably possible changes for the purpose of sensitivity analysis. Decreases to the long-term oil and gas prices from 1 January 2026 specified above would result in a further post-tax impairment of $44.9 million. A 10 per cent increase in the long-term oil and gas price deck would reduce the post-tax impairment charge by $44.9 million. Considering the discount rates, the Group believes a one per cent increase in the post-tax discount rate is considered to be a reasonable possibility for the purpose of sensitivity analysis. A one per cent increase in the post-tax discount rate would lead to a further post-tax impairment of $17.6 million, and a one per cent decrease in the post-tax discount rate would reduce the post-tax impairment charge by $19.1 million.

Sensitivity analyses indicate that reductions or increases in the long-term oil and gas prices of 10 per cent or a one per cent increase or decrease in the post-tax discount rate would not have resulted in a different impairment reversal.

11. Leases

This note provides information for leases where the Group is a lessee.

Balance sheet

Right-of-use assets

Cost	*Land and buildings $ million*	*Drilling rigs $ million*	*FPSO $ million*	*Offshore facilities $ million*	*Equipment $ million*	*Total $ million*
At 1 January 2021	66.0	129.9	-	-	3.2	199.1
Additions during the year	-	29.0	-	-	15.6	44.6
Additions from business combinations and joint arrangements	41.1	-	525.6	-	1.2	567.9
Cost revisions/remeasurements	-	(3.7)	(15.7)	-	(1.3)	(20.7)
Disposals	(5.4)	-	-	-	-	(5.4)
Currency translation adjustment	(1.4)	(2.5)	-	-	(0.5)	(4.4)
At 31 December 2021	**100.3**	**152.7**	**509.9**	**-**	**18.2**	**781.1**
Additions during the year [1]	-	-	-	338.0	-	338.0
Cost revisions/remeasurements	3.3	33.6	52.7	(3.8)	3.4	89.2
Disposals	(6.6)	-	-	-	-	(6.6)
Currency translation adjustment	(9.6)	(17.4)	-	-	(1.6)	(28.6)
At 31 December 2022	**87.4**	**168.9**	**562.6**	**334.2**	**20.0**	**1,173.1**
Accumulated depreciation						
At 1 January 2021	11.0	54.3	-	-	1.6	66.9
Charge for the year	11.6	44.8	102.1	-	5.9	164.4
Currency translation adjustment	(0.3)	(1.3)	-	-	(0.1)	(1.7)
At 31 December 2021	**22.3**	**97.8**	**102.1**	**-**	**7.4**	**229.6**
Charge for the year	11.8	42.5	107.4	61.1	7.0	229.8
Disposals	(6.4)	-	-	-	-	(6.4)
Currency translation adjustment	(1.8)	(11.8)	-	-	(1.0)	(14.6)
At 31 December 2022	**25.9**	**128.5**	**209.5**	**61.1**	**13.4**	**438.4**
Net book value						
At 31 December 2021	78.0	54.9	407.8	-	10.8	551.5
At 31 December 2022	61.5	40.4	353.1	273.1	6.6	734.7

(1) Additions of $338.0 million related to the Tolmount offshore facilities were made to the right-of-use assets during the year (2021: total additions of $612.5 million arose primarily from business combinations of $567.9 million) and $42.7 million from a new drilling rig contract.

Right-of-use liabilities	***2022 $ million***	***2021 $ million***
At 1 January	654.3	140.9
Additions	338.0	42.7
Additions from business combinations and joint arrangements	-	637.8
Re-measurement	88.9	(5.0)
Finance costs charged to income statement (note 6)	25.1	22.3
Finance costs charged to decommissioning provision (note 12)	0.6	0.7
Disposals	(0.4)	(5.1)

Lease payments	(254.0)	(160.4)
Currency translation adjustment	(27.9)	(19.6)
At 31 December	**824.6**	**654.3**
Classified as:		
Current	220.8	165.1
Non-current	603.8	489.2
Total lease liabilities	824.6	654.3

The significant portion of the Group's lease liabilities represent lease arrangements for FPSO vessels on the Catcher and Chim Sáo assets, and offshore facilities on the Tolmount asset.

The lease liabilities and associated right-of-use-assets have been calculated by reference to in-substance fixed lease payments in the underlying agreements incurred throughout the non-cancellable period of the lease along with periods covered by options to extend the lease where the Group is reasonably certain that such options will be exercised. When assessing whether extension options were likely to be exercised, assumptions are consistent with those applied when testing for impairment.

Income statement

Depreciation charge of right-of-use assets	***2022 $ million***	***2021 $ million***
Land and buildings – non-oil and gas assets	10.8	10.5
Land and buildings – oil and gas assets	1.0	1.1
Drilling rigs	42.5	44.8
Offshore facilities	61.1	-
FPSO	107.4	102.1
Equipment – non oil and gas assets	0.4	-
Equipment – oil and gas assets	6.6	5.9
	229.8	164.4
Capitalisation of IFRS 16 lease depreciation [1]		
Drilling rigs	(25.9)	(27.2)
Equipment	(4.0)	(3.5)
Depreciation charge included within consolidated income statement	199.9	133.7

(1) Of the $29.9 million (2021: $30.7 million) capitalised IFRS 16 lease depreciation, $22.4 million (2021: $22.5 million) has been capitalised within property, plant and equipment and $7.5 million (2021: $8.2 million) within provisions (note 12).

	2022 $ million	***2021 $ million***
Lease interest (included in Finance expenses – note 6)	25.1	22.3

The total cash outflow for leases in 2022 was $254.0 million (2021: $160.4 million).

12. Provisions

	Decommissioning provision $ million	*Other $ million*	*Total $ million*
At 1 January 2021	4,197.1	13.9	4,211.0
Additions	17.1	1.0	18.1
Additions from business combinations and joint arrangements	1,683.0	34.5	1,717.5
Changes in estimates – decrease to oil and gas tangible decommissioning assets	(381.0)	-	(381.0)
Changes in estimates – increase to oil and gas intangible decommissioning assets	14.3	-	14.3
Changes in estimate – credit to income statement	-	(2.3)	(2.3)
Changes in estimate on oil and gas tangible assets – debit to income statement	8.5	-	8.5
Changes in estimate on oil and gas intangible assets – credit to income statement	(6.3)	-	(6.3)
Amounts used	(225.9)	(9.2)	(235.1)
Interest on decommissioning lease	(0.7)	-	(0.7)
Depreciation, depletion & amortisation on decommissioning right-of-use leased asset	(8.2)	-	(8.2)
Release of royalty provision	-	(10.2)	(10.2)
Unwinding of discount	78.0	-	78.0
Currency translation adjustment	(22.2)	(0.2)	(22.4)
At 31 December 2021	**5,353.7**	**27.5**	**5,381.2**
Additions	24.4	-	24.4
Changes in estimates – decrease to oil and gas tangible decommissioning assets	(720.9)	-	(720.9)
Changes in estimates – decrease to oil and gas intangible decommissioning assets	(6.1)	-	(6.1)
Changes in estimate – credit to income statement	-	(1.2)	(1.2)
Changes in estimate on oil and gas tangible assets – credit to income statement	(82.3)	-	(82.3)
Changes in estimate on oil and gas intangible assets – credit to income statement	(5.7)	-	(5.7)
Amounts used	(222.6)	(2.3)	(224.9)
Disposal	(9.0)	-	(9.0)
Interest on decommissioning lease	(0.6)	-	(0.6)
Depreciation, depletion & amortisation on decommissioning right-of-use leased asset	(7.5)	-	(7.5)
Unwinding of discount	65.1	-	65.1
Currency translation adjustment	(247.2)	-	(247.2)
At 31 December 2022	**4,141.3**	**24.0**	**4,165.3**

Classified within:

	Non-current liabilities	*Current liabilities*	*Total*
	$ million	***$ million***	***$ million***
At 31 December 2021	5,022.6	358.6	5,381.2
At 31 December 2022	3,933.7	231.6	4,165.3

Decommissioning provision
All of the $24.4 million decommissioning provision additions relate to oil and gas tangible assets (2021: $14.7 million related to oil and gas tangible assets, and $2.4 million related to oil and gas intangible assets.

The Group provides for the estimated future decommissioning costs on its oil and gas assets at the balance sheet date. The payment dates of expected decommissioning costs are uncertain and are based on economic assumptions of the fields concerned. The Group currently expects to incur decommissioning costs within the next 40 years, the majority of which are anticipated to be incurred between the next 10 to 20 years. These estimated future decommissioning costs are inflated at the Group's long term view of inflation of 2.5 per cent per annum (2021: 2.0 per cent per annum) and discounted at a risk-free rate of between 3.5 per cent and 3.7 per cent (2021: 0.9 per cent and 1.8 per cent) reflecting a 6-month (2021: 24-month) rolling average of market rates over the varying lives of the assets to calculate the present value of the decommissioning liabilities. The unwinding of the discount is presented within finance costs.

These provisions have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made, which management believe are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to consider any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon market prices for the necessary decommissioning work required, which will reflect market conditions at the relevant time. In addition, the timing of decommissioning liabilities will depend upon the dates when the fields become economically unviable, which in itself will depend on future commodity prices and climate change, which are inherently uncertain.

Other provisions
Other provisions relate to termination benefit provision in Indonesia of $23.5 million (2021: $25.3 million), where the Group operates a service, severance and compensation pay scheme under a collective labour agreement with the local workforce. Other provisions at 31 December 2021 also included a $2.3 million onerous contract provision in respect of the termination cost of the rig which had been operating on the Schiehallion field, which has now been fully settled. The onerous contract had no impact on the income statement in the year.

13. Borrowings and facilities

The Group's borrowings are carried at amortised cost:

	2022 $ million	2021 $ million
Reserves based lending (RBL) facility	702.3	2,312.0
Bond	491.3	489.5
Exploration finance facility (EFF)	10.5	44.6
Other loans	34.0	39.9
Total borrowings	1,238.1	2,886.0
Classified within		
Non-current liabilities	1,216.6	2,823.7
Current liabilities	21.5	62.3
Total borrowings	1,238.1	2,886.0

Interest of $6.2 million (2021: $17.4 million) on the RBL, bond and EFF had accrued by the balance sheet date and has been classified within accruals.

The key terms of the RBL facility are:

- term matures 23 November 2027.
- facility size of $4.1 billion (with $0.75 billion accordion option).
- debt availability currently at $2.75 billion.
- debt availability to be redetermined on an annual basis
- interest at USD LIBOR plus a margin of 3.25 per cent, rising to a margin of 3.5 per cent from November 2025
- a margin adjustment linked to carbon-emission reductions
- liquidity and leverage covenant tests
- a syndication group of 19 banks.

Certain fees are also payable, including fees on available commitments at 40 per cent of the applicable margin and commission on letters of credit issued at 50 per cent of the applicable margin.

In October 2021, the Group issued a $500 million bond under Rule 144A and has a tenor of five years to maturity. The coupon was set at 5.50 per cent and interest is payable semi-annually.

Since 2019, the Group has been operating within an exploration finance facility, currently for NOK 1 billion, in relation to part-financing the exploration activities of Harbour Energy Norge AS. At the balance sheet date, the amount drawn down on the facility was NOK 104 million/$10.5 million (2021: NOK 396 million/$44.9 million).

During the year $54.9 million (2021: $38.9 million) of arrangement fees and related costs have been amortised and are included within financing costs. 2021 also included a $13.9 million modification gain following a maturity extension of the RBL debt prior to the completion of the merger in March 2021.

At 31 December 2022, $81.5 million of arrangement fees and related costs remain capitalised (2021: $136.4 million), of which $20.2 million are due to be amortised within the next 12 months (2021: $43.6 million).

At the balance sheet date, the outstanding RBL balance excluding incremental arrangement fees and related costs was $775.0 million (2021: $2,437.5 million). As at 31 December 2022, $1,972.0 million remained available for drawdown under the RBL facility (2021: $884 million). The Group has facilities to issue up to $1.5 billion of letters of credit, of which $966 million was in issue as at 31 December (2021: $796 million), mainly in respect of future abandonment liabilities.

Other loans represent a commercial financing arrangement with Baker Hughes (formerly BHGE), that covered a three-year work programme for drilling, completion and subsea tie-in of development wells on Harbour's operated assets. The loan will be repaid based on production performance, subject to a cap, in addition to three annual instalments of $9.0 million commencing on 1 December 2024, if required.

The table below details the change in the carrying amount of the Group's borrowings arising from financing cash flow.

	$ million
Total borrowings as at 1 January 2021	2,161.4
Repayment of RBL	(697.5)
Repayment of junior debt	(400.0)
Short-term debt arising on business combination	(2,219.3)
Repayment of debt – equity allocation to borrowings	942.8
Repayment of debt – cash allocation to borrowings	1,276.5
Conversion of D loan notes to equity	(134.7)
IFRS 9 modification gain	(13.9)
Repayment of financing arrangement	(9.3)
Repayment of EFF loan	(14.7)
Proceeds from drawdown of borrowing facilities	1,617.5
Proceeds from EFF loan	45.9
Proceeds from issue of bond	500.0
Loan notes redemption	(135.7)
Arrangement fees and related costs on RBL paid and capitalised	(77.2)
Arrangement fees and related costs on bond capitalised	(10.9)
Arrangement fees and related costs on EFF loan capitalised	(0.4)
Currency translation adjustment on EFF loan	(0.6)
Loan notes interest capitalised	5.6
Financing arrangement interest payable	11.6
Amortisation of arrangement fees and related costs	38.9
Total borrowings as at 31 December 2021	**2,886.0**
Repayment of RBL	(1,662.5)
Repayment of financing arrangement	(15.4)
Repayment of EFF loan	(38.6)
Proceeds from EFF loan	11.5
Currency translation adjustment on EFF loan	(7.3)
Financing arrangement interest payable	9.5
Amortisation of arrangement fees and related costs	54.9
Total borrowings as at 31 December 2022	**1,238.1**

14. Other financial assets and liabilities

The Group held the following financial instruments at fair value at 31 December 2022. The fair values of all derivative financial instruments are based on estimates from observable inputs and are all level 2 in the IFRS 13 hierarchy, except for the royalty valuation, which includes estimates based on unobservable inputs and is level 3 in the IFRS 13 hierarchy.

	31 December 2022		*31 December 2021 restated*	
	Assets	*Liabilities*	*Assets*	*Liabilities*
Current	*$ million*	*$ million*	*$ million*	*$ million*
Measured at fair value through profit and loss				
Foreign exchange derivatives	6.0	(0.1)	0.9	(2.2)
Interest rate derivatives	24.3	-	3.3	-
Fair value of embedded derivative within gas contract	-	(57.0)	-	(11.5)
Carbon swaps	-	-	36.6	(15.6)
	30.3	(57.1)	40.8	(29.3)
Measured at fair value through other comprehensive income				
Commodity derivatives	50.5	(2,114.4)	1.0	(2,135.2)
	50.5	(2,114.4)	1.0	(2,135.2)
Total current	**80.8**	**(2,171.5)**	**41.8**	**(2,164.5)**
Non-current				
Measured at fair value through profit and loss				
Interest rate derivatives	18.2	-	8.3	-
	18.2	-	8.3	-
Measured at fair value through other comprehensive income				
Commodity derivatives	84.5	(1,279.1)	1.8	(1,373.6)
	84.5	(1,279.1)	1.8	(1,373.6)
Total non-current	**102.7**	**(1,279.1)**	**10.1**	**(1,373.6)**
Total current and non-current	183.5	(3,450.6)	51.9	(3,538.1)

Fair value measurements

All financial instruments that are initially recognised and subsequently remeasured at fair value have been classified in accordance with the hierarchy described in IFRS 13 'Fair Value Measurement'. The hierarchy groups fair value measurements into the following levels based on the degree to which the fair value is observable.

- **Level 1:** fair value measurements are derived from unadjusted quoted prices for identical assets or liabilities.
- **Level 2:** fair value measurements include inputs, other than quoted prices included within level 1, which are observable directly or indirectly.
- **Level 3:** fair value measurements are derived from valuation techniques that include significant inputs not based on observable data.

	Financial assets		*Financial liabilities*	
	Level 2	*Level 3*	*Level 2*	*Level 3*
As at 31 December 2022	*$ million*	*$ million*	*$ million*	*$ million*
Fair value of embedded derivative within gas contract	-	-	(57.0)	-
Commodity derivatives	135.0	-	(3,393.5)	-
Foreign exchange derivatives	6.0	-	(0.1)	-
Carbon swaps	-	-	-	-
Interest rate derivatives	42.5	-	-	-
Total fair value	183.5	-	(3,450.6)	-

	Financial assets		*Financial liabilities*	
	Level 2	*Level 3*	*Level 2*	*Level 3*
As at 31 December 2021 as restated	*$ million*	*$ million*	*$ million*	*$ million*
Fair value of embedded derivative within gas contract	-	-	(11.5)	-
Commodity derivatives	2.8	-	(3,508.8)	-
Foreign exchange derivatives	0.9	-	(2.2)	-
Carbon swaps	36.6	-	(15.6)	-
Interest rate derivatives	11.6	-	-	-
Total fair value	51.9	-	(3,538.1)	-

There were no transfers between fair value levels in the year. The movements in the year associated with financial assets and liabilities measured in accordance with level 3 of the fair value hierarchy are shown below:

	Financial assets		*Financial liabilities*	
	2022	***2021***	***2022***	***2021***
Level 3	***$ million***	***$ million***	***$ million***	***$ million***
Fair value as at 1 January	-	9.7	-	-
Additions from business combinations and joint arrangements	-	(10.2)	-	(4.2)
Gains and (losses) recognised in the income statement	-	0.5	-	4.2
Fair value as at 31 December	-	-	-	-

Fair value movements recognised in the income statement on financial instruments are shown below.

	2022	***2021***
	$ million	***$ million***
Income included in the income statement		
Warrants	-	4.2
Remeasurement of royalty valuation	-	0.5
	-	4.7

Fair values of other financial instruments

The following financial instruments are measured at amortised cost and are considered to have fair values different to their book values.

		2022		***2021***
	Book value	***Fair value***	***Book value***	***Fair value***
	$ million	***$ million***	***$ million***	***$ million***
Bond	(491.3)	(446.4)	(489.5)	(483.0)

The fair value of the bond is within level 2 of the fair value hierarchy and has been estimated by discounting future cash flows by the relevant market yield curve at the balance sheet date. The fair values of other financial instruments not measured at fair value including cash and short-term deposits, trade receivables, trade payables and floating rate borrowings equate approximately to their carrying amounts.

Cash flow hedge accounting

The Group uses a combination of fixed price physical sales contracts and cash-settled fixed price commodity swaps and options to manage the price risk associated with its underlying oil and gas revenues. As at 31 December 2022, all of the Group's cash-settled fixed price commodity swap derivatives have been designated as cash flow hedges of highly probable forecast sales of oil and gas.

The following table indicates the volumes, average hedged price and timings associated with the Group's financial commodity derivatives. Volumes hedged through fixed price contracts with customers for physical delivery are excluded.

Position as at 31 December 2022	***2023***	***2024***	***2025***	***2026***
Oil volume hedged (thousand bbls)	10,950	7,320	2,373	-
Weighted average hedged price ($/bbl)	74.08	84.37	81.22	-
Gas volume hedged (million therms)	1,339	652	113	-
Weighted average hedged price (p/therm)	41.46	68.85	75.22	-

As at 31 December 2022, the fair value of net financial commodity derivatives designated as cash flow hedges, all executed under ISDA agreements with no margining requirements, was a net payable of $3,516.7 million (2021: $3,868.2 million) and net unrealised pre-tax losses of $3,184.6 million (2021: $3,454.2 million) were deferred in other comprehensive income in respect of the effective portion of the hedge relationships.

Amounts deferred in other comprehensive income will be released to the income statement as the underlying hedged transactions occur. As at 31 December 2022, net deferred pre-tax losses of $2,367.9 million (2021: $2,495.9 million) are expected to be released to the income statement within one year.

Interest Rate Benchmark Reform (IBOR)

From 1 January 2022, publication of most LIBOR settings ended (including Sterling LIBOR). All IBORs were replaced with alternative reference rates with the exception of US LIBOR.

After 30 June 2023 US LIBOR will cease publication and will be replaced by SOFR (Secured overnight financing rate). The Group has variable rate RBL borrowings that currently reference US LIBOR, which are partially hedged by interest rate swaps that are also linked to US LIBOR. The RBL agreement has an automatic trigger to transition to SOFR after 30 June 2023, and a similar arrangement has been agreed in principle with the interest rate swap counterparties to reduce any future impact on the financial statements after transition.

The following table shows the financial instruments held by the Group as at 31 December 2022 which are referenced to US LIBOR that will transition to SOFR by 30 June 2023.

RBL borrowings financial liabilities	***Nominal value ($ millions)***
USD 1M LIBOR	475.0
USD 6M LIBOR	300.0
	775.0
Derivatives	
Interest rate swaps USD 6M LIBOR	544.6

The nominal values in the table above also represent the carrying values net of unamortised deferred fees of the RBL as at 31 December 2022.

15. Notes to the statement of cash flows

Net cash flows from operating activities consist of:

	2022	***2021***
	$ million	***$ million***
Profit before taxation	2,461.8	314.5
Adjustments to reconcile profit before tax to net cash flows:		
Finance cost, excluding foreign exchange	358.2	309.4
Finance income, excluding foreign exchange	(77.1)	(48.8)
Depreciation, depletion and amortisation	1,545.8	1,371.0
Fair value movement in unrealised carbon swaps	2.6	-
Net impairment of property, plant and equipment	(169.6)	117.2
Taxes paid	(551.5)	(279.8)
Share based payments	16.5	8.4
Decommissioning payments	(217.0)	(244.8)
Onerous contract provision	-	(2.3)
Exploration costs written-off	64.4	255.0
Write-off of non-oil and gas assets	-	4.7
Pre-merger costs	-	7.0
Onerous contract payments	(2.3)	(9.2)
Increase in royalty consideration receivable	-	(0.5)
(Gain)/loss on termination of IFRS 16 lease	(0.2)	0.3
(Gain)/loss on disposal	(12.1)	0.1
Movement in realised cash flow hedges not yet settled	(104.3)	361.6
Unrealised foreign exchange (gain)/loss	(237.9)	57.3
Working capital adjustments:		
Decrease/(increase) in inventories	65.0	(13.0)
Increase in trade and other receivables	(75.7)	(607.4)
Increase in trade and other payables	63.2	13.5
Net cash inflow from operating activities	3,129.8	1,614.2

Reconciliation of net cash flow to movement in net borrowings

	2022	***2021***
	$ million	***$ million***
Proceeds from drawdown of borrowing facilities	-	(1,617.5)
Proceeds from issue of bond	-	(500.0)
Short-term debt arising on business combination	-	2,219.3
Repayment of debt – equity allocation to borrowings	-	(942.8)
Repayment of debt – cash allocation to borrowings	-	(1,276.5)
Conversion of D loan notes to equity	-	134.7
Proceeds from EFF loan	(11.5)	(45.9)
Repayment of RBL facility	1,662.5	697.5
Repayment of junior debt	-	400.0
Loan notes redemption	-	135.7
IFRS 9 modification gain	-	13.9
Repayment of EFF loan	38.6	14.7
Repayment of financing arrangement	15.4	9.3
Arrangement fees and related costs capitalised	-	88.5
Financing arrangement interest payable	(9.5)	(11.6)
Amortisation of arrangement fees and related costs capitalised	(54.9)	(38.9)
Currency translation adjustment on EFF loan	7.3	0.6
Loan notes interest capitalised	-	(5.6)
Movement in total borrowings	1,647.9	(724.6)
Movement in cash and cash equivalents	(199.0)	253.3
Decrease/(increase) in net borrowings in the year	1,448.9	(471.3)
Opening net borrowings	(2,187.3)	(1,716.0)
Closing net borrowings	(738.4)	(2,187.3)

Analysis of net borrowings

	2022	***2021***
	$ million	***$ million***
Cash and cash equivalents	499.7	698.7
RBL facility	(702.3)	(2,312.0)
Bond	(491.3)	(489.5)
EFF loan	(10.5)	(44.6)
Net debt	(704.4)	(2,147.4)
Financing arrangement	(34.0)	(39.9)
Closing net borrowings	(738.4)	(2,187.3)

16. Related party disclosures

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

In late 2021, the Company agreed a secondment agreement with EIG to second two employees, familiar with Harbour's business and assets, to provide additional support and expertise for Harbour for an initial period of six months from 1 December 2021. The secondment agreement provided that the secondees would work for Harbour on a substantially full-time basis which could be terminated or extended with the agreement of the parties. In May 2022, the Company and EIG agreed to terminate the agreement for one secondee and to extend the second for a further period which was subsequently terminated before the end of the year.

Harbour Energy's Viking CCS (formerly V Net Zero), the CO_2 capture, transport and storage network, entered into an arrangement with West Burton Energy, the independent power generation company based in Nottinghamshire which is a subsidiary of EIG, Harbour's largest shareholder. The intention is to capture, transport and permanently store CO2 emissions from the West Burton B power station. Harbour Energy and West Burton Energy have recently begun the necessary engineering design to connect West Burton B to the high-capacity Viking CCS storage sites located deep beneath the Southern North Sea.

Compensation of key management personnel of the Group

Remuneration of key management personnel, including Directors of the Group, is shown below.

	2022	***2021*** [(1)]
	$ million	***$ million***
Salaries and short-term employee benefits	14.6	18.6
Payments made in lieu of pension contributions	0.8	0.7
Termination benefits	0.4	-
Pension benefits	-	-
	15.8	19.3

(1) 2021 data includes remuneration of key management personnel for the Chrysaor Holdings Group in the three months to 31 March 2021.

17. Distributions made and proposed

A final dividend of 11 cents per ordinary share in relation to the year ended 31 December 2021 was paid on 18 May 2022 pursuant to shareholder approval received on 11 May 2022.

Pursuant to shareholder approval received on 11 May 2022 an interim dividend of 11 cents per ordinary share in relation to the half year ended 30 June 2022 was paid on 19 October 2022.

	2022 ***$ million***	***2021*** ***$ million***
Cash dividends on ordinary shares declared and paid:		
Final dividend for 2021: 11 cents per share (2020: no dividend)	98.3	-
Interim dividend for 2022: 11 cents per share	93.2	-
	191.5	-
Proposed dividends on ordinary shares:		
Final dividend for 2022: 12 cents per share (2021: 11 cents per share)	100.0	-

Proposed dividends on ordinary shares are subject to approval at the annual general meeting and are not recognised as a liability as at 31 December.

18. Events after the reporting period

On 14 February 2023, the Scheme's trustee effected a bulk annuity 'buy in' policy with Just Retirement Limited. This policy secures the benefits of all the Scheme's members and eliminates mortality and investment risk from the Company's balance sheet. This decision was made principally in light of the substantial improvement to the Scheme's funded status over 2022 and the favourable market conditions for such transactions. The Company was not required to pay any additional contributions to the Scheme in respect of the annuity purchase.

Glossary

- *2C* Best estimate of contingent resources
- *2P* Proven and probable reserves
- AGM Annual general meeting
- *bbl* Barrel
- *boe* Barrel of oil equivalent
- CCS Carbon capture and storage
- *CGU* Cash generating unit
- *Chrysaor* Chrysaor Holdings Limited and subsidiaries
- *DD&A* Depreciation, depletion and amortisation
- *DRIP* Dividend re-investment plan
- *EBITDAX* Earnings before interest, tax, depreciation, amortisation and exploration
- *EFF* Exploration financing facility
- *EPL* Energy Profits Levy (UK)
- *EPS* Earnings per share
- ESG Environmental, social and governance
- EUA European Union Allowance
- *FEED* Front End Engineering & Design
- *FPSO* Floating production storage offtake vessel
- *FVLCD* Fair value less cost of disposal
- *GHG* Greenhouse gas emissions
- *IAS* International Accounting Standards
- *IEA* International Energy Agency
- *IFRSs* International Financial Reporting Standards
- *kboepd* Thousand of barrels of oil equivalent per day
- $kgCO_2e$ Kilograms of carbon dioxide equivalent
- *LIBOR* London inter-bank offered rate
- *mmboe* Million barrels of oil equivalent
- *mscf* Thousand standard cubic feet
- *mt* Million tonnes
- *mtpa* Million tonnes per annum
- *NBP* Natural gas prices
- *NGFS* Network for Greening the Financial System
- *NOK* Norwegian krone
- *NTS* National Transmission System
- *PP&E* Property, plant and equipment
- *Premier* Premier Oil plc and subsidiaries
- *RBL* *Reserves based lending*
- *SOFR* Secured Overnight Financing Rate
- *Tcf* Trillion cubic feet
- *Therm* Unit of UK natural gas
- *WACC* Weighted average cost of capital
- *USD* US dollar

Non-IFRS measures

Harbour uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles (GAAP). These non-IFRS measures, which are presented within the Financial review, are defined below:

- ***Capital investment****:* Depicts how much the Group has spent on purchasing fixed assets in order to further its business goals and objectives. It is a useful indicator of the Group's organic expenditure on oil and gas assets, and exploration and appraisal assets, incurred during a period.
- ***DD&A per barrel*****:** Depreciation and amortisation of oil and gas properties for the period divided by working interest production. This is a useful indicator of ongoing rates of depreciation and amortisation of the Group's producing assets.
- ***EBITDAX*****:** Earnings before tax, interest, depreciation and amortisation, impairments, remeasurements, onerous contracts and exploration expenditure. This is a useful indicator of underlying business performance.
- ***Free cash flow*****:** Operating cash flow less cash flow from investing activities less interest and lease payments.
- ***GHG intensity:*** Reported on a gross operated basis and excluding offsets.
- ***Leverage ratio:*** Net debt/ last twelve months EBITDAX.
- ***Liquidity:*** The sum of cash and cash equivalents on the balance sheet and the undrawn amounts available to the Group on our principal facilities. This is a key measure of the Group's financial flexibility and ability to fund day-to-day operations.
- ***Net debt*****:** Total reserves based lending facility, bond and Exploration financing facility (net of the carrying value of unamortised fees) less cash and cash equivalents recognised on the consolidated balance sheet. This is an indicator of the Group's indebtedness and contribution to capital structure.
- ***Operating cost per barrel*****:** Direct operating costs (excluding over/underlift) for the period, including tariff expense, insurance costs and mark to market movements on emissions hedges, less tariff income, divided by working interest production. This is a useful indicator of ongoing operating costs from the Group's producing assets.
- ***Total capital expenditure:*** Capital investment 'additions' per notes 9 and 10 plus decommissioning expenditure 'amounts used' per note 12

Group reserves and resources

Oil and gas 2P reserves and 2C resources

	North Sea[1]			International[1]			Total[1]		
	Oil, NGLs	Gas	Total	Oil, NGLs	Gas	Total	Oil, NGLs	Gas	Total
	mmbbls	bcf	mmboe[2]	mmbbls	bcf	mmboe[2]	mmbbls	bcf	mmboe[2]
2P reserves (working interest)									
1 January 2022	232	1,208	461	11	85	27	243	1,293	488
Revisions[3]	17	(89)	1	(1)	(10)	(3)	16	(99)	(2)
Production	(36)	(183)	(71)	(1)	(18)	(5)	(38)	(202)	(76)
31 December 2022	213	936	390	9	57	19	221	993	410
2P reserves (entitlement)[4]									
31 December 2022	213	936	390	7	44	15	220	980	405
2C resources (working interest)									
1 January 2022	220	516	309	116	208	151	336	724	460
Revisions, additions, relinquishments[5]	(78)	(155)	(105)	21	449	99	(57)	295	(5)
31 December 2022	142	361	204	137	657	250	279	1,019	455

Notes:

1. North Sea consists of the UK and Norway. International consists of Indonesia, Vietnam and Mexico. Volumes reflect internal estimates. ERCE as a competent independent person has audited the Group's 2P net entitlement and working interest reserves as at 31 December 2022 and ERCE considers these to be fair and reasonable as per the SPE Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information. ERCE has also audited c. 80 per cent of the Group's 2C contingent resources as at 31 December 2022 and is of the opinion that Harbour's estimates are fair and reasonable. Further, ERCE believes that if its audit had included all of Harbour's 2C resources then it would have been able to express the same opinion.
2. Conversion of gas volumes from bcf to boe is determined using an energy conversion of 5.8 mmbtu per boe. Fuel gas is not included in these estimates.
3. 2P reserves revisions are accounted for by a downward revision of the Group's estimate of the Tolmount field 2P reserves based on the production performance of the field, partially offset by the sanction of further activity, including the Talbot field development and for a further well in the Greater Britannia Area.
4. Harbour's net entitlement 2P reserves are lower than its working interest 2P reserves for its international assets, reflecting the terms of the Production Sharing Contracts (PSC).
5. Movement in 2C resource reflects the addition of the Timpan gas discovery in Indonesia, offset by the movement of some volumes to 2P reserves, some revisions and some UK licence relinquishments.

The Group provides for amortisation of costs relating to evaluated properties based on direct interests on an entitlement basis, which incorporates the terms of the PSCs in Indonesia and Vietnam. On an entitlement basis, reserves were 405 mmboe as at 31 December 2022.

Because of rounding, some totals may not agree exactly with the sum of their component parts.

CO_2 storage capacity

	31 December 2022	31 December 2021
2C resources (million tonnes)[1]	300	-

1. Volumes reflect internal estimates. Harbour commissioned ERCE to complete a Competent Person's Report of the Storage Capacity of the Viking CCS project to the Society of Petroleum Engineers (SPE) Storage Resources Management System (SRMS) standard, and to audit Harbour's 2C storage resource estimate. This audit process has confirmed Harbour's estimate of 300 million tonnes of 2C storage resource for the Viking CCS project is fair and reasonable.