Harbour Energy plc
"Harbour" or the "Company" or the "Group"
17 March 2022

Press Release

2021 Operational highlights

- Completed merger with Premier (the Merger); realisation of synergies progressing as planned
- Production of 175 kboepd (2020: 173 kboepd); Q4 production of 214 kboepd
- Successful drilling at J-Area, Elgin Franklin, AELE, Beryl (UK) and Natuna and Tuna (Indonesia)
- 2P reserves increased to 488 mmboe, representing 157 per cent 2P reserves replacement
- Working practices adapted to protect our employees and contractors from COVID-19; Total Recordable Injury Rate of 1.27 per million hours worked
- Net Zero 2035 progress includes emissions reduction actions, continued involvement in two UK CCS projects and offsetting more than 25 per cent of our emissions
- Alignment of portfolio with Harbour's strategy, including exits from Sea Lion (Falkland Islands) and Brazil exploration licences

2021 Financial highlights[1]

- Operating cash flow of $1.6 billion (2020: $1.4 billion). Free cash flow of $678 million (2020: $562 million)
- Profit after tax of $101 million (2020: Loss after tax of $778 million)
- EBITDAX increased to $2.4 billion, up 36 per cent (2020: $1.8 billion)
- Opex and total capex lower than forecast at $15.2/boe (2020: $11.2/boe) and $935 million (2020: $698 million) respectively
- Completed $500 million debut bond issuance with a coupon of 5.5 per cent
- Year-end net debt of $2.3 billion (2020: $1.5 billion) before unamortised fees and 0.9x leverage (2020: 0.8x), in line with target of less than 1.5x through the commodity price cycle
- Introduction of an initial $200 million annual dividend; proposed final dividend of $100 million (11 cents per share) for full year 2021 to be paid in May 2022 following shareholder approval

2022 Outlook

- Production of 195-210 kboepd, a c. 15 per cent increase versus 2021; production of 219 kboepd to end February
- Tolmount (UK): platform commissioning largely complete; start-up underway
- Opex and total capex guidance unchanged at $15-16/boe and $1.3 billion respectively
- Drilling at Catcher, J-Area, Beryl (UK); Natuna and Andaman II (Indonesia); and Chim Sao (Vietnam)
- Continued progress to Net Zero by 2035, including activity on our UK CCS projects
- At $100 /bbl, 200 p/therm, forecast free cash flow (after tax and $200 million dividend) of $1.5-1.7 billion with potential to be net debt free in 2023

Continued./...

Full year results for the year ended 31 December 2021

Linda Z Cook, Chief Executive Officer, commented:

"2021 was a transformational year with completion of the Merger, our third significant transaction since 2017. As a result, we became a public company with a global footprint and the largest London-listed independent oil and gas company.

With our scale, our commitment to producing safely and responsibly, our robust balance sheet and track record of successful M&A, I believe we are well placed to deliver value creation, growth and shareholder returns.

I am proud of all we accomplished in our first year as a listed company and excited for our future."

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An analyst presentation will be held at 9.00am today and will be webcast live via our website.

[1] Definitions of Alternative Performance Measures (APMs) are included in the Glossary under Non-IFRS measures.

Full year results for the year ended 31 December 2021

Summary of 2021 performance

A strong production base

2021 production averaged 175 kboepd (2020: 173 kboepd). This reflected the addition of Premier's portfolio from the end of March partially offset by significant planned maintenance campaigns, including those deferred from 2020 due to the global pandemic. Production was also impacted by some unplanned outages in the first half, the delay to the start-up of the Tolmount project and natural decline. Production increased to 214 kboepd in the fourth quarter, supported by strong operational performance.

Operating costs were $976 million and $15.2 /boe on a unit of production basis, in line with expectations. Total capital expenditure including decommissioning was $935 million, lower than forecast due to savings across the asset base. Capital expenditure was weighted towards the second half of the year with the return of drilling activity across our operated assets to pre-COVID levels.

The strong production achieved at the end of 2021 has continued into 2022. Our production is forecast to be higher in 2022, between 195 and 210 kboepd, at the midpoint an increase of c. 15 per cent versus 2021. The increase is underpinned by a full year of production from the Premier portfolio and the new Tolmount gas field. 2022 production is also expected to benefit from lower planned maintenance levels and contributions from new wells including at the J-Area and Catcher Area in the UK, and Chim Sao in Vietnam.

A focus on safety and ESG

In Harbour, safety is our number one priority. While we recorded no serious injuries or significant spills in the year, we are not satisfied with the performance. Our Total Recordable and Lost Time Injury Rates were 1.27 and 0.68, respectively, per million hours worked. We established process safety as our key focus area and made it the topic for our inaugural Global HSES Day.

Following completion of the Merger, we standardised how we measure and report our greenhouse gas emissions and established an emissions baseline. Our Net Zero goal has been embedded into our investment decision making and we have incorporated emissions reduction incentives into our compensation and main debt facility. We also purchased our first carbon offsets, investing in independently certified forest conservation and landfill gas capture projects in Brazil.

In 2021, our GHG emissions and intensity (Scope 1 and 2), measured on a gross operated basis, were 1.6 $mtCO_2e$ and 23 kgCO2e/boe, reflecting the addition of Premier's portfolio from March and increased drilling activity. Net of the offsets acquired and retired with respect to 2021, our gross operated emissions reduced by over 25 per cent to 1.2 mtCO2e and 17 $kgCO_2e$/boe.

2021 saw good progress on our two early-stage UK CCS projects, V Net Zero and Acorn. For V Net Zero, this included the award to Harbour of a CCS license to reuse the depleted offshore Viking fields for CO_2 storage and the selection of the project by some of Humber's largest emitters as their preferred CO_2 transportation and storage provider. V Net Zero and Acorn have the potential to capture and store multiple times our annual emissions using our infrastructure and offshore depleted fields.

Capital deployment

We have significant opportunities within our asset base to support production at current levels in the near term while generating material free cash flow, and the majority of our capex is allocated to lower risk, high return investments.

Harbour Energy

Full year results for the year ended 31 December 2021

We have continued to see outperformance from infill wells drilled at the Greater Britannia Area as well as improved results from the ongoing drilling campaign at Clair. At J-Area, we recompleted the S-15 well, reinstated production from the previously shut in J-06 well and drilled the Jade South well. This successfully targeted a previously untested part of the Jade field and was brought into production in January 2022. Elsewhere at the J-Area, we completed the Dunnottar exploration well in December which did not appear to have found commercial levels of hydrocarbons. 2021 also saw successful drilling at Elgin Franklin, Everest and Beryl in the UK and Natuna Sea Block A in Indonesia.

Looking to 2022, almost all of our drilling and development projects within our approved budget of $800 million breakeven at lower than $35/bbl and 35p/therm. This expenditure supports an active rig programme across our producing portfolio, including 23 infill and development wells and several well intervention campaigns. There is also ongoing production and plant optimisation activity planned for 2022, including a number of compression projects and gas reinjection programmes, helping to underpin future production and offset natural decline.

Harbour has several organic growth projects, which together could add materially to our future production. These include the Talbot field, which is expected to be developed as a multi-well tie back to J-Area infrastructure in the UK, and the Tuna field in Indonesia. Both Talbot and Tuna were successfully appraised during 2021 and are now being progressed towards a final investment decision. Harbour also has a 12.39 per cent interest in the Zama Unit (Mexico) where the Block 7 partners and Pemex are working together to finalise a field development plan ahead of a final investment decision targeted for as early as 2023.

In 2021 we announced our decision to exit the Falklands Islands and our exploration acreage in Brazil. We believe there are lower risk and lower emissions intensive options to replace our reserves and grow than via frontier exploration or multi-billion dollar greenfield developments.

Strong reserves replacement through disciplined M&A

A key achievement in 2021 was the completion of the Merger which enhanced our UK North Sea asset base and provided us with a global footprint. Integration is well advanced, and we have started to realise the synergies and efficiencies resulting from the Merger, especially within our UK North Sea operations.

In 2021 we increased our proven and probable (2P) reserves on a working interest basis to 488 mmboe at year-end (2020: 451 mmboe), reflecting a 2P reserves replacement for the year of 157 per cent, more than offsetting 2021 production. This increase was driven by the addition of the Premier portfolio partially offset by a downward revision at the Tolmount field based on the outcome of the development drilling programme. Our 2C resources were 460 mmboe at year-end 2021 and include the addition of the Zama and Tuna fields from the Premier portfolio.

A solid financial position

During 2021, we retained a robust balance sheet, strong liquidity and diversified our capital structure. As a result of the Merger, we were admitted to trading on the London Stock Exchange and in August became a constituent of the FTSE 250 index. In October, we completed our debut $500 million bond issuance, using the proceeds to repay the Shell Junior debt facility, providing us with additional flexibility over the future marketing of our hydrocarbons.

During 2021, we generated $678 million of free cash flow. As a result, net debt excluding unamortised fees stood at $2.3 billion at year-end, down from $2.9 billion at the time of completion of the Merger. Group leverage at year-end was 0.9x, in line with our target of less than 1.5x on average through the commodity price cycle.

Our strong financial position together with predictability of our future cash flow enabled us to introduce an initial $200 million per annum dividend, with the first $100 million distribution paid in respect of the 2021 financial year in May 2022, subject to shareholder approval. Going forward, this will be paid in two equal instalments of $100 million each.

Outlook

As we enter 2022, our balance sheet is strong. The importance of this has perhaps never been more evident than it is today with the triple impacts of a global pandemic, an uneven path towards a lower carbon economy and, more recently, the conflict in Ukraine. Against this backdrop, and with volatile commodity prices, we are generating material and resilient free cash flow, underpinned by our high quality, diverse UK asset base. At $100 /bbl and 200 p/therm average prices for 2022, we expect to generate between $1.5 and $1.7 billion of free cash flow (after tax and the $200 million dividend payment) with the potential to be debt free in 2023. As a result, we have significant optionality over our future capital allocation, including for meaningful value accretive transactions and additional shareholder returns.

Financial review

Premier legally acquired Chrysaor through the issuance of shares. The transaction completed on 31 March 2021, whereupon Premier changed its name from Premier Oil Plc to Harbour Energy Plc.

For accounting purposes, the transaction constituted a reverse acquisition of Premier by Chrysaor in accordance with IFRS3, Business Combinations. As a result, Premier is fully consolidated in the financial statements with effect from 31 March 2021, and all results prior to this date represent those of Chrysaor only. For further detail, see note 12.

Summary of financial results

	Year ended 31 December 2021	Year ended 31 December 2020
Production - kboepd	175	173
Revenue and other income – $m	3,618	2,438
Operating costs per boe – $/boe	***15.2***	***11.2***
EBITDAX - US$m[1]	**2,431**	**1,784**
Pre-tax profit/(loss) – $m	315	(978)
Profit/(loss) after tax – $m	101	(778)
Earnings/(loss) per share – $/share	0.1	(1.1)
Capital expenditure – $m	709	556
Decommissioning spend – $m	226	142
Operating cashflow – $m	1,614	1,373
Free cash flow[1] – $m	**678**	**562**
Net debt [1] $m (net of unamortised fees)	**2,147**	**1,414**
Post hedging realised prices:		
Crude oil – $/boe	59	63
UK natural gas – p/therm	54	33
Singapore HSFO – $/mscf	11.7	-

[1] See Glossary for the definition of non-GAAP measures. Reconciliations between GAAP and non-GAAP measures are provided within this Financial review

Harbour reported average production for 2021 of 175 kboepd (2020: 173 kboepd), which includes nine months contribution from the Premier business, with production split between 55 per cent liquids (2020: 48 per cent) and 45 per cent gas (2020: 52 per cent).

Harbour reported total revenue and other income of $3,618 million (2020: $2,438 million). Revenue was higher than the prior period primarily as a result of higher realised gas prices on a post-hedge basis and an increase in production volumes for both liquids and gas, with a greater proportion of liquids in 2021, in part due to the Merger. Realised post-hedge crude prices were broadly unchanged.

Production costs for the period were $15.2 /boe (2020: $11.2 /boe). The increase was primarily driven by additional planned maintenance during extended summer shut-downs deferred from 2020 as a result of COVID-19. Unit production costs were also impacted by unplanned outages, well availability and natural decline, however, this was broadly offset by volumes from new wells. Additionally, production costs were also impacted by the strengthening of Pound Sterling against the US Dollar during the period.

Full year results for the year ended 31 December 2021

EBITDAX amounted to $2,431 million (2020: $1,784 million). The increase from 2020 was due to higher revenue partially offset by higher operating costs from the enlarged group.

Pre-tax profit was $315 million (2020: loss $978 million). Post-tax profits were $101 million (2020: loss $778 million). Earnings per share were $0.1 compared to a loss of $1.1 for 2020. The increase in profit and earnings per share are driven by higher revenue and lower impairments offset by higher cost of sales and exploration and evaluation expenses.

Capital and decommissioning expenditure in the period amounted to $935 million (2020: $698 million). Capital expenditure of $709 million (2020: $556 million) mainly consisted of spending on operated assets in the J-Area (Jasmine West Limb development, Talbot appraisal, Jade South and Dunnottar exploration wells), Tolmount development drilling and the Everest LAD development well. Non-operated capital expenditure included drilling programmes at Beryl, Elgin Franklin and Clair Ridge. Decommissioning spend of $226 million (2020: $142 million) related primarily to the Southern North Sea, Balmoral and the non-operated asset Hewett.

Free cash flow for the period amounted to $678 million (2020: $562 million).

As at 31 December 2021, net debt of $2,147 million (2020: $1,414 million) consisted of RBL senior debt, and a High Yield Bond, less deferred amortised fees and cash balances. The junior debt facility of $400 million was repaid during the year. The increase since the 2020 year-end is mainly due to the drawdown on the RBL facility prior to completion of the Merger to fund the replacement of Premier's debt.

Liquidity, being the amount undrawn under the RBL facility plus cash balances, was $1.6 billion at the end of the year.

Income statement

	Year ended 31 December 2021 $ million	**Year ended 31 December 2020 $ million**
Revenue and other income	3,618	2,438
Crude	2,023	1,430
Gas	1,264	805
NGL	164	138
Tariff income and other revenue	28	41
Other income	139	24
Pre-tax profit/(loss)	315	(978)
EBITDAX	2,431	1,784
Profit/(loss) after tax	101	(778)
Earnings/(loss) per share – $/share	0.1	(1.1)

Revenue

Revenue earned from hydrocarbon production and tariff income amounted to $3,618 million (2020: $2,438 million) after realised hedging losses of $1,517 million (2020: $789 million hedging gains). Some of our hydrocarbon production is sold pursuant to fixed-price contracts, as described below under 'Derivative Financial Instruments'. The rest is sold at market values, subject to standard quality and basis adjustments.

Crude oil sales amounted to $2,023 million (2020: $1,430 million), with a post-hedge realised price of $59 /boe (2020: $63 /boe). Gas revenue was $1,264 million (2020: $805 million) split UK natural gas $1,143 million (2020: 805 million) and international $121 million (2020: $nil). The post-hedge realised price for UK natural gas was 54 p/therm (2020: 33 p/therm) and for Indonesian gas was $11.7/mscf (2020: nil). Condensate sales and tariff amounted to $191 million (2020: $163 million).

Other income amounted to $139 million (2020: $24 million) and includes mark-to-market gains on UK emissions derivatives of $51 million and a receipt of $40 million from ConocoPhillips in relation to an adjustment to consideration for Chrysaor's purchase of the ConocoPhillips UK business in 2019.

	31 December 2021 $ million	31 December 2020 $ million
Operating costs		
Field operating costs (1)	1,003	731
Tariff income	(27)	(24)
Total	976	707
Field operating costs per barrel ($ per barrel)	15.2	11.2
Depreciation, Depletion and Amortisation (DD&A) **(**before impairment)		
Depreciation of oil and gas assets (cost of operations only)	1,327	1,191
Depreciation of non-oil and gas assets	42	29
Amortisation of intangible assets	2	2
Total	1,371	1,222
DD&A before impairment charges ($ per barrel)	21.4	19.3

(1) includes mark to market gains on EUA emissions hedges of $51 million included in Other Revenue, excludes non-cash depreciation on non-oil and gas assets

Production costs

Production costs for the period were $15.2 /boe (2020: $11.2 /boe). The increase was primarily driven by additional planned maintenance during extended summer shut-downs deferred from 2020 as a result of COVID-19. Unit production costs were also impacted by unplanned outages, well availability and natural decline, however, this was broadly offset by volumes from new wells. Additionally, production costs were also impacted by the strengthening of Pound Sterling against the US Dollar during the period.

The increase in the weighted average DD&A rate from 2020 is due to higher DD&A charges on right-of-use leased assets acquired as part of the Merger.

EBITDAX

EBITDAX amounted to $2,431 million (2020: $1,784 million) due to higher revenues partially offset by higher operating costs as a result of the higher commodity prices and higher production.

	31 December 2021 $ million	31 December 2020 $ million
Operating profit/(loss)	640	(687)
Exploration and evaluation and new ventures	50	13
Exploration costs written-off	255	161
Depreciation, depletion and amortisation	1,371	1,222
Impairment of property, plant and equipment	117	644
Impairment of goodwill	-	411
Provision for onerous contract	(2)	19
Remeasurements	-	1
EBITDAX	**2,431**	**1,784**

Exploration and evaluation expenditure and new ventures

During the period the Group expensed $255 million (2020: $161 million) for exploration and appraisal activities. This includes costs associated with the exit from exploration acreage in Brazil and the Sea Lion project in the Falkland Islands of $134 million (2020: $nil). This also includes costs associated with relinquishments of UK licenses and uncommercial drilling results on the UK Dunnottar well and Norwegian PL973 Jerv and Ilder prospects of $121 million (2020: $161 million). In addition, exploration and evaluation expenditure and new ventures amount to $50 million (2020: $13 million), mainly related to pre-development costs associated with UK Carbon Capture and Storage projects and corporate expenditure in Norway related to regional seismic and time-writing costs.

Impairment and DD&A charges

Impairment charges for property, plant and equipment pre-tax were $117 million (2020: $644 million) driven primarily by the cessation of production from the Millom field in the East Irish Sea assets, and from a single producing field in the UK North Sea as a result of underlying reservoir performance. There was no impairment of goodwill (2020: $411 million). Depreciation unit expense was $21 /boe (2020: $19 /boe) with the increase due to higher DD&A charges on right-of-use leased assets acquired as part of the Merger.

Net financing costs

Financing expenses totalled $375 million (2020: $302 million), including $113 million of interest expenses incurred on debt facilities and legacy Chrysaor shareholder loan-notes (2020: $124 million). Also included are bank and facility fees of $63 million (2020: $36 million), foreign exchange losses of $65 million (2020: $40 million), lease interest of $22 million (2020: $7 million) and the unwinding of the discount on provisions, primarily associated with future decommissioning obligations, of $78 million (2020: $88 million).

Finance income amounted to $49 million (2020: $11 million), including gains on derivatives of $15 million (2020: $nil), gains of $10 million on foreign exchange forward contracts (2020: $4 million) and a one-off modification gain recognised on the amendment of the RBL facility of $14 million.

Taxation

The tax expense for the year amounted to $213 million (2020: credit $199 million), split between a current tax expense of $192 million (2020: $336 million), and a deferred tax expense of $21 million (2020: credit $535 million) and representing an effective rate of 68 per cent (2020: 20 per cent). The increase in the effective tax rate is predominantly driven by higher non-deductible expenses in respect of the Group's exit from the Falklands and Brazil which are non-recurring plus unrecognised tax losses in relation to corporate acquisition debt expenses.

Earnings and earnings per share

Profit after tax was $101 million (2020: loss $778 million). The improved result for 2021 is primarily due to higher revenue and other income in 2021, and lower impairment charges on oil and gas assets and goodwill. Earnings per share was $0.1 /share (2020: loss $1.1 /share).

Dividends

The Board is proposing a dividend of 11 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 11 May 2022. If approved, the dividend will be paid on 18 May 2022 to shareholders on the register as of 8 April 2022. 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 26 April 2022.

Statement of Financial Position

	Year ended 31 December 2021 $ million	**Year ended 31 December 2020 $ million**
Total non-current assets, excluding deferred taxes	10,273	8,193
Deferred taxes (note 6)	1,938	-
Total current assets	2,294	1,290
Total assets	**14,505**	**9,483**
Total equity	**(474)**	**(1,068)**
Total borrowings net of transaction fees (note 14)	(2,886)	(2,182)
Total abandonment provisions (note 13)	(5,354)	(4,197)
Deferred taxes (note 6)	(187)	(1,031)
Lease creditor	(654)	(141)
Other liabilities	(4,950)	(864)
Total liabilities	**(14,031)**	**(8,415)**
Net debt (note 15)	**(2,147)**	**(1,414)**

Assets

At 31 December 2021, total assets amounted to $14,505 million (Dec 2020: $9,483 million), of which current assets were $2,294 million (Dec 2020: $1,290 million) and deferred tax assets $1,938 million (Dec 2020: $nil).

The increase in total assets is mainly due to the inclusion of Premier assets on completion of the Merger which added total assets of $5,204 million including property, plant and equipment of $2,386 million, exploration and evaluation assets of $597 million and deferred tax assets recognised of $1,549 million. The Merger also added goodwill of $339 million. Further information related to the Merger is included in note 12.

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.

	31 December 2021 $ million	**31 December 2020 $ million**
Additions to oil and gas assets (note 10)	(464)	(415)
Additions to fixtures and fittings, office equipment & IT software (notes 9 and 10)	(35)	(51)
Additions to exploration and evaluation assets (note 9)	(210)	(90)
Total capital investment	**(709)**	**(556)**
Movements in working capital	42	(58)
Capitalised lease payments	23	16
Cash capital expenditure per the cash flow statement	**(644)**	**(598)**

During the period, the Group incurred capital investment of $709 million (2020: $556 million). Capital expenditure mainly consisted of spending on operated assets in the J-Area (Jasmine West Limb development, Talbot appraisal, the Jade South and Dunnottar exploration wells), Tolmount development drilling and Everest LAD development well. Non-operated capital expenditure included drilling programmes at Beryl, Elgin Franklin and Clair Ridge.

Liabilities

At 31 December 2021, total liabilities amounted to $14,031 million (Dec 2020: $8,415 million) including decommissioning provisions of $5,354 million (Dec 2020: $4,197 million) and borrowings of $2,886 million (Dec 2020: $2,182 million).

The increase in total liabilities is mainly due to the inclusion of Premier's liabilities of $5,263 million on completion of the Merger, drawdown on the RBL facility in order to fund the replacement of Premier's debt prior to completion of the Merger and increased hedging liabilities as a result of increased commodity prices. The total liabilities included from the Merger consisted mainly of additional debt of $2,219 million which was fully settled as part of completion, provisions for decommissioning of $1,683 million and right-of-use asset lease liabilities of $638 million. Further information is included in note 12.

As at 31 December 2021, net debt of $2,147 million (Dec 2020: $1,414 million) consisted of RBL senior debt and an unsecured bond, less deferred unamortised fees and cash balances. The increase since year end 2020 is mainly due to the drawdown on the RBL facility prior to completion of the Merger to fund the replacement of Premier's debt. Debt is stated net of the unamortised portion of the issue costs and bank fees of $136 million (Dec 2020: $73 million).

Equity and reserves

Total equity amounted to $474 million (Dec 2020: $1,068 million) with changes in 2021 reflecting the accounting for the merger as a reverse acquisition in accordance with IFRS3, Business Combinations, with the capital structure (share capital and share premium) being a continuation of the legal acquirer (Premier Oil plc), whilst the remaining reserves reflect the accounting acquirer (Chrysaor Holdings Limited). The reduction in equity reflects the negative fair value on the Group's commodity hedging programme at 31 December 2021 which is mainly accounted for through other comprehensive income, within equity.

Cash flow[1]

	31 December 2021 $ million	31 December 2020 $ million
Cash flow from operating activities after tax	1,614	1,373
Cash flow from investing activities – capital investment	(644)	(598)
Cash flow from investing activities – acquired on business combination	97	-
Cash flow from investing activities – other	(24)	(5)
Operating cash flow after investing activities	**1,043**	**770**
Cash flow from financing activities – net interest and lease payments	(365)	(208)
Free cash flow	**678**	**562**
Cash and cash equivalents	**699**	**445**

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

Net cash from operating activities after tax amounted to $1,614 million (2020: $1,373 million) after accounting for tax payments of $280 million (2020: $190 million) and working capital movements of $607 million (2020: $46 million). Cash flow used in investing activities on capital expenditure was $644 million (2020: $598 million). Cash outflow from financing activities (excluding movements in debt principal)- interest and lease payments, were $365 million ($208 million). Cash balances were $699 million (2020: $445 million) at the end of the period.

Risk management

Principal risks

There are no significant changes to the headline principal risks from those disclosed in the 2021 Interim results. A full description of Harbour's principal risks will be disclosed in its 2021 Annual Report & Accounts.

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 2021. These are set out in the following table. Hedges realised to date are in respect of both crude oil and natural gas.

Hedge position	**2022**	**2023**	**2024**	**2025**
Oil				
Volume hedged (mmboe)	18.80	7.30	-	-
Average price hedged ($/bbl)	61.15	61.05	-	-
Gas				
Volume hedged (mmboe)	25.37	23.00	8.33	1.55
Average priced hedged (p/therm)	50.75	40.86	43.05	44.55

At 31 December 2021, our financial hedging programme on commodity derivative instruments showed a pre-tax negative fair value of $3,868 million (2020: positive fair value of $142 million) included in other financial assets and liabilities, with no ineffectiveness charge to the income statement.

Post balance sheet events

As announced on 2 February 2022, Phil Kirk stepped down from his role as Executive Director with effect from 28 February 2022.

The Group has assessed and will continue to assess the implications of the events in Ukraine. Currently there is considered to be no material impact to the Group's financial performance or position.

The Company confirmed that the Directors intend to submit a proposal to shareholders at the Company's forthcoming Annual General Meeting for a general authority to purchase the Company's own Ordinary shares. The Directors believe that the Board should be afforded the flexibility to be able to buy back the Company's shares when it is in the best interests of shareholders to do so and will result in an increase in earnings per share. The resolution will specify the maximum number of shares that can be acquired (approximately 15 per cent of the issued Ordinary share capital) and the minimum and maximum prices at which they may be bought. Any shares purchased under the authority granted by the resolution will either be cancelled or may be held as treasury shares. In accordance with the Listing Rules, a further announcement would be made by the Company in the event that the Directors intend to commence a programme to repurchase shares.

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. 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. During the year, the Group extended the maturity of its RBL facility from December 2025 to November 2027.

The Group's base case going concern assessment assumes: an oil price of $75 /bbl and $70 /bbl and average NBP gas price of 150 p/therm and 100 p/therm in 2022 and 2023, respectively; production in line with approved asset plans and the ongoing capital requirements of the Group will be financed by existing RBL and High Yield 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 and in the Group's production of 10 per cent throughout the going concern period, which is the period up to June 2023. In these combined downside scenarios applied to the base case forecast, the Group is forecasted to have sufficient financial headroom and no covenant breach 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 at 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	*2021* *$ million*	*2020* *$ million*
Revenue	3	3,478.8	2,413.6
Other income	3	139.2	24.2
Cost of operations		(2,453.2)	(1,847.2)
Impairment of property, plant and equipment	10	(117.2)	(644.0)
Impairment of goodwill	8	-	(411.4)
Exploration and evaluation expenses and new ventures	4	(49.8)	(13.2)
Exploration costs written-off	4	(255.0)	(160.8)
General and administrative expenses		(102.5)	(48.6)
Operating profit/(loss)	4	640.3	(687.4)
Finance income	5	48.8	11.4
Finance expenses	5	(374.6)	(301.7)
Profit/(loss) before taxation		314.5	(977.7)
Income tax (expense)/credit	6	(213.4)	199.3
Profit/(loss) for the financial year		101.1	(778.4)

Consolidated Statement of Comprehensive Income
For the year ended 31 December

	2021 *$ million*	2020 *$ million*
Profit/(loss) for the financial year	101.1	(778.4)
Items that may be subsequently reclassified to income statement in subsequent periods		
Fair value losses on cash flow hedges	(3,583.8)	(173.7)
Tax credit on cash flow hedges	1,433.2	71.3
Currency exchange differences	(5.7)	27.4
Total other comprehensive loss for the financial year, net of tax	(2,156.3)	(75.0)
Total comprehensive loss for the financial year	(2,055.2)	(853.4)
Attributable to equity holders of the parent	(2,055.2)	(853.4)

Earnings per share

For the year ended 31 December

		2021 cents	2020 cents
Basic and diluted	7	11.6	(110.4)

Consolidated balance sheet

As at 31 December	Note	2021 $ million	2020 $ million
Assets			
Non-current assets			
Goodwill	8	1,327.1	990.0
Other intangible assets	9	873.7	454.1
Property, plant and equipment	10	7,246.7	6,522.4
Right-of-use assets	11	551.5	132.2
Deferred tax assets	6	1,938.4	-
Other receivables		263.0	3.6
Other financial assets		10.1	90.4
Total non-current assets		12,210.5	8,192.7
Current assets			
Inventories		211.4	160.5
Trade and other receivables		1,342.2	461.3
Other financial assets		41.8	222.6
Cash and cash equivalents		698.7	445.4
Total current assets		2,294.1	1,289.8
Total assets		14,504.6	9,482.5
Equity and liabilities			
Equity			
Share capital		171.1	0.1
Share premium		1,504.6	910.0
Capital redemption reserve		8.1	-
Merger reserve		677.4	-
Cash flow hedge reserve		(2,062.1)	80.2
Costs of hedging reserve		1.5	9.8
Currency translation reserve		98.3	104.0
Retained earnings/(accumulated losses)		74.6	(36.8)
Total equity		473.5	1,067.3
Non-current liabilities			
Borrowings	14	2,823.7	2,160.3
Provisions	13	5,022.6	4,020.8
Deferred tax	6	187.1	1,031.4
Trade and other payables		32.3	29.8
Lease creditor	11	489.2	80.8
Other financial liabilities		1,373.6	52.5
Total non-current liabilities		9,928.5	7,375.6
Current liabilities			
Trade and other payables		873.6	540.3
Borrowings	14	62.3	21.5
Lease creditor	11	165.1	60.1
Provisions	13	358.6	190.2
Current tax liabilities		116.8	153.3
Other financial liabilities		2,526.2	74.2
Total current liabilities		4,102.6	1,039.6
Total liabilities		14,031.1	8,415.2
Total equity and liabilities		14,504.6	9,482.5

Consolidated statement of changes in equity

For the year ended 31 December 2021

	Share capital $ million	*Share premium $ million*	*Merger reserve $ million*	*Capital redemption reserve $ million*	*Cash flow hedge reserve (i) $ million*	*Costs of hedging reserve (i) $ million*	*Currency translation reserve $ million*	*(Accumulated losses)/ Retained earnings $ million*	*Total equity $ million*
As at 1 January 2020	0.1	910.0	-	-	176.1	16.3	76.6	729.8	1,908.9
Loss for the financial year	-	-	-	-	-	-	-	(778.4)	(778.4)
Share based payments	-	-	-	-	-	-	-	11.8	11.8
Other comprehensive profit/(loss)	-	-	-	-	(95.9)	(6.5)	27.4	-	(75.0)
At 31 December 2020	0.1	910.0	-	-	80.2	9.8	104.0	(36.8)	1,067.3
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 (ii)	-	987.1	41.5	-	-	-	-	-	1,028.6
Profit for the financial year	-	-	-	-	-	-	-	101.1	101.1
Share based payments	-	-	-	-	-	-	-	13.4	13.4
Purchase of ESOP Trust shares	-	-	-	-	-	-	-	(3.1)	(3.1)
Other comprehensive loss	-	-	-	-	(2,142.3)	(8.3)	(5.7)	-	(2,156.3)
At 31 December 2021	171.1	1,504.6	677.4	8.1	(2,062.1)	1.5	98.3	74.6	473.5

The Merger constituted a 'reverse takeover' of Premier by Chrysaor and has therefore been accounted for as a reverse acquisition in accordance with IFRS 3 Business Combinations. The effect on the statement of changes in equity is that the capital structure (Share capital and Share premium) is a continuation of the legal acquirer (Premier Oil plc), whilst the remaining reserves reflect the accounting acquirer (Chrysaor Holdings Limited).

(i) Disclosed net of deferred tax
(ii) Debt settlement relates to the issuance of shares in partial settlement of Premier's debt.

Consolidated statement of cash flows

For the year ended 31 December

	Note	2021 $ million	2020 $ million
Net cash inflow from operating activities	15	1,614.2	1,373.4
Cash flows from investing activities			
Expenditure on exploration and evaluation assets		(176.5)	(88.3)
Expenditure on property, plant and equipment		(437.4)	(457.6)
Expenditure on non-oil and gas intangible assets		(30.0)	(52.2)
Cash acquired on business combinations	12	97.4	-
Receipts for sub-lease income		7.4	-
Expenditure on business combinations – contingent consideration		-	(12.5)
Expenditure on business combinations – deferred consideration		(46.0)	-
Finance income received		14.1	7.4
Net cash outflow from investing activities		(571.0)	(603.2)
Cash flows from financing activities			
Repayment of senior debt	14	(697.5)	(774.0)
Repayment of junior debt	14	(400.0)	-
Repayment of financing arrangement	14	(9.3)	(1.6)
Repayment of exploration financing facility	14	(14.7)	(8.7)
Repayment of short-term debt arising on business combination	14	(1,276.5)	-
Repayment of hedging liabilities arising on business combination		(48.5)	-
Proceeds from new borrowings – exploration financing facility	14	45.9	12.8
Proceeds from new borrowings – senior debt	14	1,617.5	157.5
Proceeds from new borrowings – High Yield Bond	14	500.0	-
Purchase of ESOP Trust shares		(3.1)	-
Lease payments	11	(160.4)	(60.5)
Redemption of loan notes	14	(135.7)	(77.1)
Interest paid and bank charges		(204.9)	(147.8)
Net cash outflow from financing activities		(787.2)	(899.4)
Net increase/(decrease) in cash and cash equivalents		256.0	(129.2)
Effect of exchange rates on cash and cash equivalents		(2.7)	1.4
Cash and cash equivalents at 1 January		445.4	573.2
Cash and cash equivalents as at 31 December		698.7	445.4

Notes to the financial statements

1. Corporate information

The consolidated financial statements of Harbour Energy plc (Harbour or the Company, formerly Premier Oil plc) for the year ended 31 December 2021 which comprise the Company and all its subsidiaries (the Group), were authorised for issue in accordance with a resolution of the Directors on 16 March 2022. Harbour Energy plc is a limited liability company incorporated in Scotland and listed on the London Stock Exchange. The Company's registered office is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh, EH1 2EN, United Kingdom.

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 Merger constituted a 'reverse takeover' of Premier by Chrysaor and has therefore been accounted for as a reverse acquisition in accordance with IFRS 3 Business Combinations. As a result, Premier is fully consolidated in the financial statements with effect from 31 March 2021, and all results prior to this date represent those of Chrysaor only.

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.

Basis of preparation and presentation of financial information

The consolidated financial statements of the Group have been prepared on a going concern basis in accordance with International Financial Reporting Standards (IFRSs) in conformity with the requirements of the Companies Act 2006 and UK adopted international accounting standards. 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. Further details are within the financial review.

The financial information for the year ended 31 December 2021 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 2020 have been delivered to the Registrar of Companies and those for 2021 will be delivered following the Company's annual general meeting. The auditor has reported on these accounts; their reports were 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.

The Group financial statements are presented in US Dollars ($) 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.

Full year results for the year ended 31 December 2021

This preliminary announcement is consistent with the audited financial statements of the Group for the year-ended 31 December 2020. 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 11 May 2022.

Accounting policies

The accounting policies which follow set out those policies which apply in preparing the financial statements for the year ended 31 December 2021. All accounting policies are consistent with those adopted and disclosed in Chrysaor's 2020 Annual Report and Accounts, other than where new policies have been adopted, and the comparatives are those of Chrysaor.

In addition, following the merger with Premier who had material FPSO lease arrangements, the Group has adopted Premier's leasing accounting policy in relation to lease arrangements of a joint operation, see Leases.

2. 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 3.

Income statement

	2021 *$ million*	*2020* *$ million*
Revenue		
North Sea	3,268.2	2,413.6
International	210.6	-
Total Group Revenue	3,478.8	2,413.6
Other income		
North Sea	139.0	24.2
International	0.2	-
Total Group Revenue and other income	3,618.0	2,437.8
Group operating profit/(loss)		
North Sea	699.3	(687.4)
International	(59.0)	-
Group operating profit/(loss)	640.3	(687.4)
Finance income	48.8	11.4
Finance expenses	(374.6)	(301.7)
Profit/(loss) before taxation	314.5	(977.7)
Income tax (expense)/credit	(213.4)	199.3
Profit/(loss) for the financial year	101.1	(778.4)

Balance sheet

	2021 *$ million*	*2020* *$ million*
Segment assets		
North Sea	13,325.8	9,482.5
International	1,178.8	-
Total assets	14,504.6	9,482.5

	2021 *$ million*	*2020* *$ million*
Segment liabilities		
North Sea	(13,379.6)	(8,415.2)
International	(651.5)	-
Total liabilities	(14,031.1)	(8,415.2)

Segment information (continued)

	2021 $ million	2020 $ million
Other information		
Capital expenditure		
North Sea	640.7	556.3
International	68.4	-
Total capital expenditure	709.1	556.3

	2021 $ million	2020 $ million
Depreciation, depletion and amortisation		
North Sea	1,299.8	1,222.1
International	71.2	-
Total depreciation, depletion and amortisation	1,371.0	1,222.1

	2021 $ million	2020 $ million
Exploration and evaluation expenses and new ventures		
North Sea	45.4	13.2
International	4.4	-
Total exploration and evaluation expenses and new ventures	49.8	13.2

Exploration costs written-off of $255.0 million (2020: $160.8 million) comprise $133.9 million (2020: $nil) related to the International segment, in connection with the Group's exits from exploration acreage in Brazil and the Sea Lion project in the Falkland Islands, and $121.1 million (2020: $160.8 million) of write-offs in the North Sea business unit, primarily related to uncommercial drilling results from the Dunnottar, Jerv and Ilder exploration wells, and UK licence relinquishments.

3. Revenue and other income

	2021 $ million	2020 $ million
Crude oil sales	2,023.4	1,430.1
Gas sales	1,264.0	805.2
Condensate sales	163.6	138.4
Hydrocarbon revenue	3,451.0	2,373.7
Tariff income	27.2	24.1
Other revenue	0.6	15.8
Total revenue from production activities	3,478.8	2,413.6
Other income	139.2	24.2
Total revenue and other income	3,618.0	2,437.8

Revenue of $4,996.0 million (2020: $1,624.6 million) was from contracts with customers. This excludes realised hedging losses on crude and gas sales in the year of $1,517.2 million (2020: $789.0 million gain).

Other income mainly represents mark to market and realised gains on EUA emissions hedges of $51.0 million (2020: $0.3 million), a $40.0 million receipt from ConocoPhillips in relation to an adjustment to consideration relating to Chrysaor's purchase of the ConocoPhillips UK business in 2019 (2020: nil), $17.5 million in respect of Research and Development Expenditure credits (2020: $nil) and $26.0 million partner recovery on IFRS 16 lease accounting (2020: $23.9 million).

Approximately 84 per cent (2020: 95 per cent) of the revenues were attributable to sales to energy trading companies of the Shell group.

The revenues for 2021 include the nine months of oil and gas production from the Premier Oil business following the all-share Merger described in note 12.

4. Operating profit

This is stated after charging/(crediting):

	2021 *$ million*	*2020* *$ million*
Movement in over/underlift balances and hydrocarbon inventories	9.6	(119.9)
Production, insurance and transportation costs	1,085.5	754.2
Gas purchases	28.4	-
Royalties	3.8	-
Depreciation of oil and gas assets (note 10)	1,204.1	1,168.9
Depreciation of non-oil and gas assets (note 10)	5.5	5.7
Amortisation of non-oil and gas intangible assets (note 9)	26.1	17.2
Depreciation of right-of-use oil and gas assets (note 11)	153.9	50.6
Depreciation of right-of-use non-oil and gas assets (note 11)	10.5	6.2
Amortisation of capacity rights (note 9)	1.6	1.7
Capitalisation of IFRS 16 lease depreciation on oil and gas assets (note 11)	(30.7)	(28.2)
Impairment of property, plant and equipment (note 10)	117.2	644.0
Impairment of goodwill (note 8)	-	411.4
Onerous contract provision (note 13)	(2.3)	18.5
Exploration and evaluation expenditure and new ventures	49.8	13.2
Exploration costs written-off (note 9)	255.0	160.8
Remeasurement of royalty valuation	(0.5)	1.3
Remeasurement of acquisition completion adjustments	-	0.4
Remeasurement – loss/(gain) on termination of lease	0.3	(0.5)
Auditors' remuneration		
Audit fees		
Fees payable to the Company's auditor for the Company's Annual Report	3.1	0.7
Audit of the Company's subsidiaries pursuant to legislation	3.1	0.5
Non audit fees		
Other services pursuant to legislation – interim review	0.3	-
Other services[i]	0.4	0.6

Exploration and evaluation expenditure and new ventures of $49.8 million (2020: $13.2 million) includes $14.4 million (2020: $nil) of early project costs on new ventures incurred in respect of the Group's interest in Carbon Capture and Storage (CCS) projects.

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

[i] Other services in 2021 primarily relate to reporting accountant services provided by EY in respect of the acquisition or other corporate transactions. These services are typically provided by a company's auditors, and the Audit and Risk Committee concluded that shareholder value was best served by appointing our auditors for this work.

Operating profit (continued)

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.

5. Finance income and finance expenses

	2021 *$ million*	*2020* *$ million*
Finance income:		
Bank interest receivable	0.9	2.8
IFRS 9 modification impact	13.9	-
Lease finance income	3.2	-
Finance income on deferred revenue	1.2	-
Realised gains on foreign exchange forward contracts	10.0	3.9
Gain on derivatives	14.5	-
Exchange differences and other gains	1.9	-
Other interest	3.2	4.7
	48.8	11.4
Finance expenses:		
Interest payable on Reserves Based Lending and junior facilities	101.6	98.5
Interest payable on loan notes	5.6	25.4
Interest payable on High Yield Bond	5.7	-
Other interest and finance expenses	16.6	5.9
Realised losses on interest rate swaps	2.4	0.7
Derivative losses	14.6	-
Lease interest	22.3	7.2
Foreign exchange losses	65.2	40.0
Bank and financing fees	63.4	36.1
Unwinding of discount on deferred consideration	-	0.1
Unwinding of discount on decommissioning and other provisions	78.0	87.8
	375.4	301.7
Finance costs capitalised during the year	(0.8)	-
	374.6	301.7

Bank and financing fees include an amount of $38.9 million (2020: $17.0 million) relating to the amortisation of arrangement fees and related costs capitalised against the Group's long-term borrowings (note 14).

Net other interest includes an $11.6 million charge (2020: $4.9 million) which represents interest under a financing arrangement (note 14).

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 3.7 per cent to the expenditures on the qualifying assets.

Effective March 2021, the Group extended the maturity of its RBL facility from December 2025 to November 2027. The amended terms did not represent a substantial modification to the terms of the facility and, therefore, the debt was not derecognised. A modification gain of $13.9 million (2020: $ nil) was recognised on amendment of the facility.

6. Income tax

The major components of income tax expense/(credit) for the years ended 31 December 2021 and 2020 are:

	2021 *$ million*	*2020* *$ million*
Current income tax expense:		
UK corporation tax	202.2	355.7
Overseas tax	(5.2)	(18.2)
Adjustments in respect of prior years	(4.9)	(1.9)
Total current income tax expense	192.1	335.6
Deferred tax expense/(credit):		
UK corporation tax	7.7	(545.6)
Overseas tax	(10.3)	13.0
Adjustments in respect of prior years	23.9	(2.3)
Total deferred tax expense/(credit)	21.3	(534.9)
Tax expense/(credit) in the income statement	213.4	(199.3)

The tax expense/(credit) in the income statement is disclosed as follows:

Income tax expense/(credit) on continuing operations	213.4	(199.3)
	213.4	(199.3)

The tax (credit) in the statement of comprehensive income is as follows:

Tax (credit) on cash flow hedges	(1,433.2)	(71.3)
	(1,433.2)	(71.3)

A reconciliation between total tax expense/(credit) and the profit/(loss) 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 2021 and 2020 is as follows:

	2021 *$ million*	*2020* *$ million*
Profit/(loss) before taxation	314.5	(977.7)
Group profit/(loss) before taxation at 40.0% (2020: 40.0%)	125.8	(391.1)
Effects of:		
Expenses not deductible for tax purposes	56.8	176.6
Interest not deductible for supplementary charge	13.1	7.6
Adjustments in respect of prior years	19.0	(4.2)
Movement in unrecognised deferred tax assets	27.4	17.3
Income not taxable	-	(5.7)
Impact of losses relieved at different rates	4.0	20.7
Investment allowance	(32.7)	(20.5)
Total tax expense/(credit) reported in the consolidated income statement	213.4	(199.3)

Income tax (continued)

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.

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.

Deferred tax

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

	2021 $ million	*2020 $ million*
Deferred tax assets	1,938.4	-
Deferred tax liabilities	(187.1)	(1,031.4)
Total deferred tax	1,751.3	(1,031.4)

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.

	Accelerated Capital Allowances $ million	*Decom-missioning $ million*	*Losses $ million*	*Fair Value of Derivatives $ million*	*Other $ million*	*Overseas $ million*	*Total $ million*
As at 1 January 2020	(3,160.6)	1,588.9	-	(128.9)	53.0	(1.6)	(1,649.2)
Deferred tax credit	532.8	25.8	-	-	(10.7)	(13.0)	534.9
Comprehensive income	-	-	-	71.3	-	-	71.3
Foreign exchange	(22.7)	26.0	-	0.5	1.1	(1.4)	3.5
Additions from business combinations and joint arrangements	-	-	-	-	8.1	-	8.1
As at 31 December 2020	***(2,650.5)***	***1,640.7***	***-***	***(57.1)***	***51.5***	***(16.0)***	***(1,031.4)***
Additions from business combinations and joint arrangements (note 12)	(569.0)	564.0	1,530.6	8.4	15.2	(183.1)	1,366.1
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
As at 31 December 2021	(2,820.1)	2,012.9	1,314.5	1,392.1	38.8	(186.9)	1,751.3

The Group's deferred tax assets as at 31 December 2021 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 and business combination accounting (note 12). 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.

Income tax (continued)

The Group has unrecognised UK tax losses and allowances as at 31 December 2021 of approximately $343.1 million (2020: $12.5 million) in respect of ring fence losses, $104.4 million (2020: $nil) in respect of ring fence investment allowance and $741.5 million (2020: $203.2 million) in respect of non-ring fence losses.

The Group also has unrecognised tax losses of approximately $212.8 million (2020: $nil) in respect of its international operations. These losses include amounts of $148.5 million which will expire, primarily within 5 years.

No deferred tax has been provided on unremitted earnings of overseas subsidiaries, based on UK tax legislation which provides exemption for foreign dividends from the scope of UK corporation tax, where relevant conditions are satisfied.

Changes in tax rate

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 did not have a material impact on the Group as the UK profits are primarily subject to the UK ring fence tax rate.

7. Earnings per Share

The calculation of basic earnings/(loss) per share is based on the profit/(loss) after tax and the weighted average number of Ordinary Shares in issue during the period. Basic and diluted earnings per share are calculated as follows:

	2021 $ million	2020 $ million
Earnings/(loss) for the period		
Earnings/(loss) for the purpose of basic earnings per share	101.1	(778.4)
Effect of dilutive potential ordinary shares	-	-
Earnings/(loss) for the purpose of diluted earnings per share	101.1	(778.4)
Number of shares (millions)		
Weighted average number of Ordinary shares for the purpose of basic earnings per share	871.2	705.0
Dilutive potential Ordinary shares	1.3	-
Weighted average number of Ordinary shares for the purpose of diluted earnings per share	872.5	705.0
Earnings/(loss) per share (cents)		
Basic	11.6	(110.4)
Diluted	11.6	(110.4)

The weighted number of average shares in the comparative period and prior to the acquisition date is based on number of shares of the legal acquiree multiplied by the exchange ratio established in the Merger agreement. From the date of acquisition, the weighted number of Ordinary Shares are that of the legal acquirer.

The effect of equity warrants and certain share options outstanding at 31 December 2021 were anti-dilutive as their exercise price was greater than market price and, therefore, was not included in the calculation of diluted earnings/(loss) per share.

8. Goodwill

	2021 $ million	2020 $ million
Cost and Net Book Value:		
At 1 January	990.0	1,404.3
Additions (note 12)	339.3	-
Impairment charge	-	(411.4)
Finalisation of 2019 business combination	-	(5.3)
Currency translation adjustment	(2.2)	2.4
At 31 December 2021	1,327.1	990.0

Goodwill represents the difference between the aggregate of the fair value of purchase consideration transferred at the acquisition date and the fair value of the identifiable assets.

The goodwill balance consists of balances arising from the completion of the all-share Merger between Premier Oil plc and Chrysaor Holdings Limited in March 2021, on Chrysaor Holdings Limited's acquisition of the ConocoPhillips UK business, and of the UK North Sea assets from Shell, which completed on 30 September 2019 and 1 November 2017 respectively.

Goodwill acquired through business combinations has been allocated to two groups of cash-generating units ('CGU's), being North Sea, of $1,278.1 million (2020: $990.0 million) and International, of $49.0 million (2020: $nil), and these are therefore the lowest levels at which goodwill is reviewed.

Impairment testing of goodwill

In accordance with IAS 36 Impairment of Assets, goodwill has been reviewed for impairment at the year-end. In assessing whether goodwill has been impaired, the carrying amount of the CGU for goodwill is compared with its recoverable amount.

The Group tests goodwill annually for impairment, or more frequently if there are indications that goodwill might be impaired. At the year-end, the Group tested for impairment in accordance with accounting policy and no impairment was identified (2020: impairment of $411.4 million).

Determining recoverable amount

The recoverable amounts of the CGU and fields have been determined on a fair value less costs to sell basis. The key assumptions used in determining the fair value are often subjective, such as the future long-term oil and gas price assumption, or the operational performance of the assets. Discounted cash flow models comprising asset-by-asset life of field projections using Level 3 inputs (based on IFRS 13 fair value hierarchy) have been used to determine the recoverable amounts. The cash flows have been modelled on a post-tax and post-decommissioning basis, inflated at 2 per cent per annum from 1 January 2024, and discounted at the Group's post-tax discount rate of between 8 and 10.5 per cent (2020: 8 per cent). Risks specific to assets within the CGU are reflected within the cash flow forecasts.

Key assumptions used in calculations

Assumptions involved 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.

Goodwill (continued)

Management's commodity price curve assumptions are benchmarked against a range of external forward price curves on a regular basis. The first two years reflect the market forward prices curves transitioning to a long-term price thereafter. The long-term commodity prices used were $65 per barrel for crude and 60p per therm for gas, which are inflated at 2 per cent per annum from 1 January 2024.

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 and they are assessed at least annually by management and by an independent consultant. Proven and probable reserves are determined using estimates of oil and gas in place, recovery factors and future commodity prices.

Operating expenditure, capital expenditure and decommissioning costs, which have been inflated at 2 per cent per annum from 1 January 2024, 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), considering both debt and equity. The cost of equity is derived from an expected return on investment by the Group's investors, and the cost of debt is based on its interest-bearing borrowings. Segment risk is incorporated by applying a beta factor based on publicly available market data. The discount rate is based on an assessment of a relevant peer group's post-tax 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
The Group has run sensitivities on its long-term commodity price assumptions, which have been based on long-range forecasts from external financial analysts, using alternate long-term price assumptions, and discount rates. These are considered to be reasonably possible changes for the purposes of sensitivity analysis. No impairment arose on the Group's goodwill under any of the sensitivity scenarios.

9. Other intangible assets

	Oil & gas assets $ million	*Non-oil & gas assets $ million*	*Capacity rights $ million*	*Total $ million*
Cost:				
At 1 January 2020	425.2	40.0	10.0	475.2
Additions	90.1	50.2	-	140.3
Reduction in decommissioning asset (note 13)	(3.0)	-	-	(3.0)
Disposals	-	-	-	-
Transfers to property, plant and equipment	32.6	-	-	32.6
Unsuccessful exploration written-off	(160.8)	-	-	(160.8)
Currency translation adjustment	7.2	4.7	0.3	12.2
At 31 December 2020	391.3	94.9	10.3	496.5
Additions	210.0	30.2	-	240.2
Additions from business combinations and joint arrangements (note 12)	596.7	0.4	-	597.1
Increase in decommissioning asset (note 13)	10.4	-	-	10.4
Transfers to property, plant and equipment	(139.5)	-	-	(139.5)
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
Accumulated amortisation:				
At 1 January 2020	-	16.0	5.6	21.6
Charge for the year	-	17.2	1.7	18.9
Currency translation adjustment	-	1.6	0.3	1.9
At 31 December 2020	-	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

Other intangible assets (continued)

Net book value:				
At 31 December 2020	391.3	60.1	2.7	454.1
At 31 December 2021	813.4	59.2	1.1	873.7

The exploration write-off of $255.0 million (2020: $160.8 million), which relates to costs associated with licence relinquishments and uncommercial well evaluations, is net of a $6.3 million credit (2020: $nil) relating to the effect of changes in decommissioning provisions on oil and gas intangible assets previously written-off.

Other intangible assets (continued)

An increase to decommissioning assets of $10.4 million (2020: decrease of $3.0 million) was made during the year as a result of an update to decommissioning estimates (note 13).

Non-oil and gas assets relate primarily to Group IT software. 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 have a remaining useful life of one year and are amortised on a contractual volume basis.

10. Property, plant and equipment

	Oil and gas Assets $ million	Fixtures and fittings & office equipment $ million	Total $ million
Cost:			
At 1 January 2020	9,258.3	21.1	9,279.4
Additions	414.9	1.1	416.0
Transfers to intangible assets	(32.6)	-	(32.6)
Increase in decommissioning asset (note 13)	257.6	-	257.6
Currency translation adjustment	97.8	0.6	98.4
At 31 December 2020	9,996.0	22.8	10,018.8
Additions	464.5	4.4	468.9
Additions from business combinations and joint arrangements (note 12)	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 13)	(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
Accumulated depreciation:			
At 1 January 2020	1,613.1	9.8	1,622.9
Charge for the year	1,168.9	5.7	1,174.6
Impairment charge	644.0	-	644.0
Currency translation adjustment	54.2	0.7	54.9
At 31 December 2020	3,480.2	16.2	3,496.4
Charge for the year	1,204.1	5.5	1,209.6
Impairment charge	117.2	-	117.2
Property, plant and equipment (continued)			
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
Net book value:			
At 31 December 2020	6,515.8	6.6	6,522.4
At 31 December 2021	7,237.1	9.6	7,246.7

During the year, the Group recognised a pre-tax impairment charge of $117.2 million (post-tax $70.3 million) (2020: pre-tax $644.0 million; post-tax $386.4 million) within the income statement. This represents a write-down of property, plant and equipment assets of $108.7 million (2020: $712.1 million) and a pre-tax impairment of $8.5 million (2020: $68.1 million credit) in respect of revisions to decommissioning estimates on the Group's non-producing assets with no remaining net book value (see note 13).

Property, plant and equipment (continued)

The impairment to property, plant and equipment arises primarily due to cessation of production from the Millom field, part of the Group's East Irish Sea assets, and from a single CGU in the UK North Sea, driven primarily by underlying reservoir performance. Impairments on property, plant and equipment are reversible in the future.

Key assumptions used in calculations

Assumptions involved 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.

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. 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 two years reflect the market forward prices curves transitioning to a long-term price from 2024, thereafter inflated at 2 per cent per annum. The long-term commodity prices used were $65 per barrel for crude and 60p per therm for gas.

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.

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 Weighted Average Cost of Capital (WACC), see note 8 for further details. Foreign exchange rates are based on management's long-term rate assumptions, with reference to a range of underlying economic indicators.

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 specified above would result in a further post-tax impairment of $73.3 million. A 10 percent increase in the long-term oil and gas price deck would reduce the post-tax impairment charge by $35.7 million. Considering the discount rates, the Group believes a 1 per cent increase in the post-tax rate is considered to be a reasonable possibility for the purpose of sensitivity analysis. A 1 percent increase in the post-tax rate would lead to a further post-tax impairment of $28.3 million, and a 1 per cent decrease in the post-tax rate would reduce the post-tax impairment charge by $31.1 million. The impairment was calculated as detailed above.

A decrease in the decommissioning assets of $357.8 million (2020: increase of $257.6 million) was made during the year as a result of both new obligations and an update to the decommissioning estimates (note 13).

Further information on additions from business combinations and joint arrangements can be found in note 12.

Property, plant and equipment (continued)

Included within property, plant and equipment additions of $468.9 million (2020: $416.0 million) are associated cash flows of $437.4 million (2020: $457.6 million) and non-cash flow movements of $31.5 million (2020: ($41.6 million)), represented by a $9.0 million increase in capital accruals (2020: $58.2 million decrease) and $22.5 million of capitalised lease depreciation (2020: $16.6 million).

11. Leases – right-of-use assets

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

Right-of-use assets	*2021* *$ million*	*2020* *$ million*
Land and buildings	78.0	54.9
Drilling rigs	54.9	75.6
FPSO	407.8	-
Equipment	10.8	1.7
	551.5	132.2

Lease liabilities	*2021* *$ million*	*2020* *$ million*
Current	165.1	60.1
Non-Current	489.2	80.8
	654.3	140.9

Additions of $612.5 million, which arise primarily from business combinations (see note 12) of $567.9 million and $42.7 million from a new drilling rig contract, were made to the right-of-use assets during the year (2020: $nil).

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

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.

Leases – right-of-use assets (continued)

(ii) The consolidated income statement includes the following amounts relating to leases:

Depreciation charge of right-of-use assets

	2021 *$ million*	*2020* *$ million*
Land and buildings – non-oil and gas assets	10.5	6.2
Land and buildings – oil and gas assets	1.1	1.0
Drilling rigs	44.8	48.3
FPSO	102.1	-
Equipment	5.9	1.3
	164.4	56.8
Capitalisation of IFRS 16 lease depreciation		
Drilling rigs	(27.2)	(27.4)
Equipment	(3.5)	(0.8)
Depreciation charge included within consolidated income statement	133.7	28.6

Of the $30.7 million (2020: $28.2 million) capitalised IFRS16 lease depreciation, $22.5 million (2020: $16.6 million) has been capitalised within property, plant and equipment and $8.2 million (2020: $11.6 million) within provisions (note 13).

	2021 *$ million*	*2020* *$ million*
Lease interest (included in finance expenses – note 5)	22.3	7.2

The total cash outflow for leases in 2021 was $160.4 million (2020: $60.5 million).

12. Business combinations and acquisition of interests in joint arrangements

Business combinations during the year ended 31 December 2021

In October 2020, Harbour Energy Limited entered into an agreement with Premier regarding an all-share Merger between Premier and Harbour Energy Limited's subsidiary, Chrysaor Holdings Limited. Under the terms of the Merger, Premier legally acquired Chrysaor through the issuance of consideration shares whilst Chrysaor was the acquirer 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 (Harbour).

The Merger constituted a 'reverse takeover' of Premier by Chrysaor and has therefore been accounted for as a reverse acquisition in accordance with IFRS 3 Business Combinations. As a result, Premier is fully consolidated in the financial statements with effect from 31 March 2021, and all results prior to this date represent those of Chrysaor only.

Premier was an upstream exploration and production company with its primary assets located in the UK North Sea, Vietnam and Indonesia. The Merger brought together two complementary businesses and created the largest independent oil and gas company listed on the London Stock Exchange with a strong balance sheet and significant international growth opportunities.

A Purchase Price Allocation (PPA) exercise has been performed under which the identifiable assets and liabilities of Premier were recognised at fair value.

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

	Fair value *$ million*
Assets	
Exploration, evaluation and other intangible assets	597.1
Property, plant and equipment – oil and gas assets	1,814.3
Property, plant and equipment – non-oil and gas assets	4.2
Property, plant and equipment – right-of-use assets	567.9
Long-term receivables	258.8
Deferred tax	1,549.2
Inventories	15.2
Trade and other receivables	291.0
Derivative financial instruments	9.2
Cash and cash equivalents	97.4
	5,204.3
Liabilities	
Trade and other payables	(317.5)
IFRS 16 lease liabilities	(637.8)
Deferred tax	(183.1)
Provision for decommissioning	(1,683.0)
Derivative financial instruments	(153.7)
Short-term debt	(2,219.3)
Deferred income	(33.6)
Other provisions	(34.5)
	(5,262.5)
Fair value of identifiable net liabilities acquired	(58.2)

Business combinations and acquisition of interests in joint arrangements (continued)

Fair value of shares acquired	285.7
Transaction cost adjustments	(4.6)
Cost of acquisition	281.1
Goodwill recognised	339.3

A provisional PPA exercise was completed and presented within the Group's 2021 Half-Year results. As is permitted under IFRS 3 Business Combinations, if during a maximum measurement period of one year from the acquisition date, the Group identifies additional assets or liabilities based on new information obtained about facts and circumstances that existed at the acquisition date, then those assets and liabilities should be recognised at that date.

As a result, the decommissioning provision has increased by $130.2 million from that presented in the provisional PPA presented in the Half-Year results, and the deferred tax asset increased by $40.4 million, resulting in a net increase to goodwill of $89.8 million.

The fair values of the oil and gas assets and intangible assets acquired have been determined using valuation techniques based on discounted cash flows using forward curve commodity prices and estimates of long-term prices, a discount rate based on market observable data and cost and production profiles generally consistent with the 2P reserves acquired with each asset. Where applicable other observable market information has also been used. The decommissioning provisions recognised have been estimated based on Harbour's internal estimates with reference to observable market data, including rig rates.

The fair value of debt facilities has been determined based on the total fair value of cash paid and new shares issued to creditors to satisfy Premier's historical debt arrangements.

The consideration was measured using the closing market price of Premier's ordinary share capital and the number of shares in issue immediately before the acquisition date. The transaction cost adjustments relate to share based payment charges accruing prior to 31 March 2021 and certain transaction costs settled by Premier on behalf of Chrysaor which have been recognised as an expense within general and administrative expenses.

Goodwill of $339.3 million has been recognised on the acquisition, representing the excess of the total consideration transferred over the fair value of the net assets acquired. The goodwill arises principally because of the following factors:

1. The ability to deliver cost synergies as a result of combining the two businesses
2. The avoidance of costs that would otherwise have been incurred by Chrysaor as a result of an initial stock exchange listing
3. The expertise and experience of the acquired business, particularly with respect to fulfilling the obligations of a UK listed entity
4. The requirement to recognise deferred tax liabilities for the difference between the assigned fair values and the tax bases of assets acquired

Business combinations and acquisition of interests in joint arrangements (continued)

None of the goodwill is deductible for corporation tax.

Acquisition related costs of $13.5 million and $26.5 million were incurred by the Group and recognised as an expense within general and administrative expenses within 2020 and 2021 respectively.

From the date of acquisition, the acquired business contributed $815.6 million of revenue and a loss of $89.0 million to the profit before tax from continuing operations of the Group. Had the acquisition completed at 1 January 2021, the business would have contributed revenue of $1,078.5 million in the year to 31 December 2021, and a loss of $93.9 million towards the profit before tax.

13. Provisions

	Decommissioning provision $ million	*Other $ million*	*Total $ million*
At 1 January 2020	3,949.8	-	3,949.8
Additions	29.9	18.5	48.4
Changes in estimates – increase to oil and gas tangible decommissioning assets	227.7	-	227.7
Changes in estimates – decrease to oil and gas intangible decommissioning assets	(3.0)	-	(3.0)
Amounts used	(142.0)	(5.4)	(147.4)
Amounts recovered from prior owner	4.0	-	4.0
Interest on decommissioning lease	(1.4)	-	(1.4)
Depreciation, depletion & amortisation on decommissioning right-of-use leased asset	(11.6)	-	(11.6)
Unwinding of discount	87.8	-	87.8
Currency translation adjustment	55.9	0.8	56.7
At 31 December 2020	4,197.1	13.9	4,211.0
Additions	17.1	1.0	18.1
Additions from business combinations and joint arrangements (note 12)	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

Provisions (continued)

Classified within:

	Non-current liabilities $ million	*Current liabilities $ million*	*Total $ million*
At 31 December 2020	4,020.8	190.2	4,211.0
At 31 December 2021	5,022.6	358.6	5,381.2

Of the $17.1 million (2020: $29.9 million) decommissioning provision additions, $14.7 million (2020: $29.9 million) relates to oil and gas tangible assets, and $2.4 million (2020: nil) 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 over the next 40 years, the majority of which are anticipated to be incurred between the next 10 to 20 years. Decommissioning provisions are discounted at a risk-free rate of between 0.9 per cent and 1.8 per cent (2020: 1.2 per cent and 2.1 per cent) and 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 relate to a provision for an onerous contract in respect of the termination cost of the rig which had been operating on the Schiehallion field, but no future approved activities have resulted in the contract being terminated. Also included within other provisions is a termination benefit provision in Indonesia of $25.3 million (2020: nil), where the Group operates a Service, Severance and Compensation pay scheme under a Collective Labour Agreement with the local workforce.

14. Borrowings and facilities

The Group's borrowings are carried at amortised cost.

	2021 *$ million*	2020 *$ million*
Reserves Based Lending facility	2,312.0	1,448.6
Junior facility	-	396.4
High Yield Bond	489.5	-
10% Unsecured D loan notes 2027	-	264.8
Exploration finance facility	44.6	14.1
Other loans	39.9	37.5
	2,886.0	2,161.4
Classified within		
Non-current liabilities	2,823.7	2,160.3
Current liabilities	62.3	21.5
	2,886.0	2,181.8
Non-current assets (deferred fees)	-	(0.1)
Current assets (deferred fees)	-	(20.3)
	2,886.0	2,161.4

The deferred fees shown in current and non-current assets reflect the expected amortisation of fees within earlier periods where there is no expected repayment of principal.

Interest of $17.4 million (2020: $2.8 million) on the Reserve Based Lending facility (RBL), High Yield Bond and Exploration Finance Facility (EFF) had accrued by the balance sheet date and has been classified within accruals.

The key terms of the RBL facility are:
- term extended to 23 November 2027
- facility size now at $4.5 billion (with $0.75 billion accordion option)
- debt availability currently at $3.32 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
- the incorporation of a margin adjustment linked to carbon-emission reductions
- the syndication group now stands at 19 banks.

The $400 million junior facility was fully repaid and cancelled in October 2021 through issuance of a $500 million High Yield Bond. The remaining proceeds were used to pay legal fees and pay down some of the drawn debt on the senior facility. The bond was issued 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.

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

Borrowings and facilities (continued)

Since 2019, Chrysaor has been operating within an exploration finance facility, currently for NOK 1 billion, in relation to part-financing the exploration activities of Chrysaor Norge AS. At the balance sheet date, the amount drawn down on the facility was NOK 396 million/$44.9 million (2020: NOK 124 million/$14.5 million).

A further $77.2 million of arrangement fees and related costs were capitalised in 2021 following amendments to the RBL facility which became effective from March 2021, related to replacement of Premier's debt prior to completion of the Merger. In addition, $10.9 million of arrangement fees and related costs were capitalised as part of the issuance of the High Yield Bond in October 2021, and $0.4 million capitalised following further drawdowns on the EFF. These amounts are being amortised over the term of the relevant arrangement. At 31 December 2021, $136.0 million of arrangement fees and related costs remain capitalised (2020: $72.5 million), of which $43.6 million are due to be amortised within the next 12 months (2020: $20.4 million).

During the year $38.9 million (2020: $17.0 million) of arrangement fees and related costs have been amortised and are included within financing costs. Also included is a $13.9 million modification gain (2020: nil) following a maturity extension of the Reserve Based Lending (RBL) debt prior to the completion of the Merger.

At the balance sheet date, the outstanding RBL balance excluding incremental arrangement fees and related costs was $2,438 million (2020: $1,918 million including the $400 million junior facilities). As at 31 December 2021, $884 million remained available for drawdown under the RBL facility.

On 15 March 2021, a partial cash redemption of the 10 percent unsecured D loan notes of $135.7 million took place, and on 30 March 2021, the outstanding balance of the D loan notes, with a principal and accrued interest value of $134.7 million, was exchanged for 16,186,811 F ordinary shares of £0.0001 each.

The Group has facilities to issue up to $1.25 billion of letters of credit, of which $796 million was in issue as at 31 December (2020: $557 million), mainly in respect of future abandonment liabilities.

Other loans represent a commercial financing arrangement with Baker Hughes (formerly BHGE), covering a three-year work programme for drilling, completion and subsea tie-in of development wells on Harbour's operated assets. As part of the deal, Baker Hughes contributes to the costs of the work programme by funding a portion of the capital expenditure, in exchange for a greater exposure to returns, as well as risks, should certain targets and success criteria, both operational and geological, be met. Interest on this financing arrangement has been calculated using the effective interest method with reference to the expected cash flows, using an estimated reserve case.

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

Borrowings and facilities (continued)

	$ million
Total borrowings as at 1 January 2020	2,822.7
Repayment of senior debt	(774.0)
Repayment of financing arrangement	(1.6)
Repayment of exploration financing facility	(8.7)
Proceeds from drawdown of borrowing facilities	157.5
Proceeds from exploration financing facility	12.8
Loan notes redemption	(77.1)
Arrangement fees and related costs on senior debt paid and capitalised	(18.4)
Currency translation adjustments	0.8
Loan notes interest capitalised	25.4
Financing arrangement interest payable	5.0
Amortisation of arrangement fees and related costs	17.0
Total borrowings as at 31 December 2020	2,161.4
Repayment of senior debt	(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 exploration financing facility loan	(14.7)
Total borrowings as at 31 December 2020 (continued)	
Proceeds from drawdown of borrowing facilities	1,617.5
Proceeds from exploration financing facility loan	45.9
Proceeds from issue of High Yield Bond	500.0
Loan notes redemption	(135.7)
Arrangement fees and related costs on senior debt paid and capitalised	(77.2)
Arrangement fees and related costs on High Yield 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

15. Notes to the statement of cash flows

Net cash flows from operating activities consist of:

	2021 $ million	2020 $ million
Profit/(loss) before taxation	314.5	(977.7)
Finance cost, excluding foreign exchange	309.4	261.7
Finance income, excluding foreign exchange	(48.8)	(7.5)
Depreciation, depletion and amortisation	1,371.0	1,222.1
Impairment of property, plant and equipment	117.2	644.0
Impairment of goodwill	-	411.4
Taxes paid	(279.8)	(189.6)
Share based payments	8.4	11.8
Decommissioning payments	(244.8)	(162.1)
Onerous contract provision	(2.3)	18.5
Exploration costs written-off	255.0	160.8
Write-off of non-oil and gas assets	4.7	-
Pre-Merger costs	7.0	-
Remeasurement of acquisition completion adjustments	-	0.4
Onerous contract payments	(9.2)	(5.4)
(Increase)/decrease in royalty consideration receivable	(0.5)	2.4
Loss/(gain) on termination of IFRS 16 lease	0.3	(0.5)
Loss on disposal of asset	0.1	-
Movement in realised cash flow hedges not yet settled	361.6	(5.6)
Unrealised foreign exchange loss	57.3	34.7
Working capital adjustments:		
Increase in inventories	(13.0)	(11.2)
(Increase)/decrease in trade and other receivables	(607.4)	41.5
Increase/(decrease) in trade and other payables	13.5	(76.3)
Net cash inflow from operating activities	1,614.2	1,373.4

Harbour Energy

Full year results for the year ended 31 December 2021

Notes to the statement of cash flows (continued)

Reconciliation of net cash flow to movement in net borrowings

	2021 $ million	2020 $ million
Proceeds from drawdown of borrowing facilities	(1,617.5)	(157.5)
Proceeds from issue of High Yield 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 exploration financing facility loan	(45.9)	(12.8)
Repayment of senior debt	697.5	774.0
Repayment of junior debt	400.0	-
Loan notes redemption	135.7	77.1
IFRS 9 modification gain	13.9	-
Repayment of exploration financing facility loan	14.7	8.7
Repayment of financing arrangement	9.3	1.6
Arrangement fees and related costs capitalised	88.5	18.4
Financing arrangement interest payable	(11.6)	(4.9)
Amortisation of arrangement fees and related costs capitalised	(38.9)	(17.1)
Currency translation adjustment on EFF loan	0.6	(0.8)
Loan notes interest capitalised	(5.6)	(25.4)
Movement in total borrowings	(724.6)	661.3
Movement in cash and cash equivalents	253.3	(127.8)
(Increase)/decrease in net borrowings in the year	(471.3)	533.5
Opening net borrowings	(1,716.0)	(2,249.5)
Closing net borrowings	(2,187.3)	(1,716.0)

Analysis of net borrowings

	2021 $ million	2020 $ million
Cash and cash equivalents	698.7	445.4
Reserves Based Lending facility	(2,312.0)	(1,448.6)
High Yield Bond	(489.5)	-
Junior facility	-	(396.4)
Exploration financing facility	(44.6)	(14.1)
Net debt	(2,147.4)	(1,413.7)
Shareholder loan notes	-	(264.8)
Financing arrangement	(39.9)	(37.5)
Closing net borrowings	(2,187.3)	(1,716.0)

16. Dividends

A dividend of $100.0 million is proposed for the year ended 31 December 2021 (2020: nil).

17. Post Balance Sheet Events

As announced on 2 February 2022, Phil Kirk stepped down from his role as Executive Director with effect from 28 February 2022.

The Group has assessed and will continue to assess the implications of the events in Ukraine. Currently there is considered to be no material impact to the Group's financial performance or position.

The Company confirmed that the Directors intend to submit a proposal to shareholders at the Company's forthcoming Annual General Meeting for a general authority to purchase the Company's own Ordinary shares. The Directors believe that the Board should be afforded the flexibility to be able to buy back the Company's shares when it is in the best interests of shareholders to do so and will result in an increase in earnings per share. The resolution will specify the maximum number of shares that can be acquired (approximately 15 per cent of the issued Ordinary share capital) and the minimum and maximum prices at which they may be bought. Any shares purchased under the authority granted by the resolution will either be cancelled or may be held as treasury shares. In accordance with the Listing Rules, a further announcement would be made by the Company in the event that the Directors intend to commence a programme to repurchase shares.

Full year results for the year ended 31 December 2021

Glossary

2C	Contingent resources
2P	Proven and probable reserves
Bbl	Barrel
BMS	Business management system
Boe	Barrel of oil equivalent
Boepd	Barrel of oil equivalent per day
CEO	Chief executive officer
CUI	Corrosion under insulation
DD&A	Depreciation, depletion and amortisation
DNV	Det Norske Veritas-Germanischer Lloyd
EFF	Exploration financing facility
ESR	Elected safety representative
FID	Final investment decision
FEED	*Front End Engineering & Design*
FPS	Forties pipeline system
HSEx	Health & Safety Executive
HSEQ	Health, safety, environment and quality
MAE	Major accident event
mboepd	Thousand barrels of oil equivalent per day
mmboe	Million barrels of oil equivalent
MPE	Ministry of Petroleum and Energy, Norway
OPPC	Oil pollution prevention and control
OPRED	Offshore Petroleum Regulator for Environment & Decommissioning
OSDR	Offshore Safety Directive Regulator
PCOA	Put and call options agreement
POP	Platform operating procedure
SWE	Safe working essentials
TAR	Turnaround
TRIF	Total recordable incident frequency
WOSPS	West of Shetland pipeline system

Full year results for the year ended 31 December 2021

Non-IFRS measures

- *EBITDAX*: is defined as earnings before tax, interest, depreciation and amortisation, impairments, remeasurements, onerous contracts and exploration expenditure. This is a useful indicator of underlying business performance
- *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
- *Depreciation, depletion and amortisation (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.
- *Free Cash Flow*: operating cash flow less cash flow from investing activities less interest and lease payments
- *Leverage ratio*: Net Debt/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 senior and junior debt, High Yield 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
- *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

Full year results for the year ended 31 December 2021

Group reserves and resources

For the year ended 31 December 2021

Group 2P reserves and 2C resources									
	North Sea[1]			International[1]			Total[1]		
	Oil and NGLs mmbbls	Gas bcf	Total mmboe[2]	Oil And NGL mmbbls	Gas bcf	Total mmboe[2]	Oil And NGLs mmbbls	Gas bcf	Total mmboe[2]
2P reserves (working interest):									
At 31 December 2020[3]	234.1	1,136.1	451.2	-	-	-	234.1	1,136.1	451.2
Acquisition[4]	42.8	323.5	102.9	12.7	126.9	36.1	55.5	450.4	139.0
Revisions[5]	(11.7)	(114.3)	(33.6)	(0.3)	(26.1)	(5.0)	(11.9)	(140.5)	(38.6)
Production	(33.4)	(136.9)	(59.8)	(1.3)	(16.0)	(4.2)	(34.7)	(152.9)	(64.1)
At 31 December 2021	**231.8**	**1,208.4**	**460.7**	**11.2**	**84.8**	**26.9**	**242.9**	**1,293.2**	**487.5**
2P reserves (entitlement)[6]									
At 31 December 2021	**231.8**	**1,208.4**	**460.7**	**8.8**	**64.0**	**20.5**	**240.6**	**1,272.4**	**481.1**
2C resources (working interest)									
At 31 December 2021	**220.0**	**516.1**	**309.2**	**115.5**	**207.8**	**151.2**	**335.5**	**723.9**	**460.4**

Notes:

1. 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 2021 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 2021 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 as at 31 December 2020 reflect internal estimates of Chrysaor's reserves as at that date.
4. 2P Acquisition volumes reflects Premier's volumes acquired following the completion of the Merger on 31 March 2021. Acquisition volumes have been adjusted from Premier year-end 2020 estimates through deduction of production from Q1 2021 and removal of fuel gas, which Harbour does not include in 2P reserves estimates.
5. The most material 2P reserves revision is related to the Tolmount field based on the outcome of the 2021 development drilling programme.
6. 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.

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 481.1 mmboe as at 31 December 2021. This was calculated at 31 December 2021, using the following oil and gas price assumptions: $75 /bbl and 150 p/therm in 2022, $70 /bbl and 100 p/therm in 2023 and $65 /bbl and 60 p/therm in real terms thereafter.