TULLOW OIL PLC - 2024 FULL YEAR RESULTS

Continued strategic and operational delivery

On track to address upcoming debt maturities

Production optimisation activities underway

25 March 2025 – Tullow Oil plc (Tullow), the independent oil and gas exploration and production group (Group), announces its Full Year Results for the year ended 31 December 2024. Details of a management presentation and webcast that will be held at 09:00 today are available on the last page of this announcement or visit the Group's website: www.tullowoil.com

Richard Miller, Interim Chief Executive Officer and Chief Financial Officer, Tullow Oil plc, commented:

"In 2024 we had a number of succeses but also some operational challenges, most notably with Jubilee production and a reserves revision, however there is now strong momentum within the business with a return to drilling at Jubilee, and the commencement of production optimisation and reserves maturation activities in Ghana. In addition a number of key achievements have recently been realised, including the resolution of the Ghana Branch Profits Remittance Tax arbitration which eliminated a material overhang, the repayment of our 2025 senior notes and as announced on 24 March, the signed binding heads of terms for the sale of our Gabonese assets for a cash consideration of $300 million. This will accelerate our deleveraging progress this year.

"I am clear on the levers required to unlock Tullow's full potential. The team remains fully focused on our near-term priorities; advancing our refinancing plan, reducing costs, optimising production activities at Jubilee and TEN, and driving reserve growth. We will continue to maintain our financial discipline and prioritise investments that add value and deliver high returns.

"Tullow's core strength as a trusted partner with a cash generative business and attractive assets with reserves growth opportunities positions us well as we lay the foundations for value creation."

2024 FULL YEAR RESULTS

- Group working interest oil and gas production averaged 61.2 kboepd (2023: 62.7 kboepd).
- Revenue of $1,535 million (2023: $1,634 million), including $74 million hedge costs (2023: $139 million).
- Capital expenditure[1] of $231 million (2023: $380 million) and decommissioning expenditure including cash provisioning for future decommissioning of $60 million (2023: $67 million).
- Adjusted EBITDAX[1] of $1,152 million (2023: $1,151 million); gross profit of $754 million (2023: $765 million); profit after tax of $55 million (2023: loss of $110 million), including exploration costs writen off of $213 million (2023: $27 million).
- Free cash flow[1] (FCF) of $156 million (2023: $170 million).
- Net debt[1] at year end reduced to $1,452 million (2023: $1,608 million); cash gearing of net debt[1] to adjusted EBITDAX[1] of 1.3 times (2023: 1.4 times); liquidity headroom of $715 million (2023: $1,000 million).
- Audited 2P reserves at year end 2024 of 164.5 mmboe (2023: 212.2 mmboe), valued at $2.5 billion (NPV10), with the reserves reduction including 22.4 mmboe of Group production.
- Successful extension of the $250 million Revolving Credit Facility (RCF) to 30 June 2025.
- Successful resolution of the Ghana Branch Profits Remittance Tax (BPRT) arbitration, which removed a potential $320 million liability and endorses the sanctity of our Petroleum Agreements.
- Five new Jubilee wells (three producers and two water injectors) brought onstream, bringing the drill programme to an end approximately six months ahead of schedule with no recordable safety incidents, and saving over $88 million (gross) compared to the initial budget.
- Average FPSO uptime at Jubilee and TEN of 97%.
- Decommissioning activities in Mauritania accelerated and completed in 2024, ahead of schedule and below budget.
- Significant milestone reached with the Ghana Forestry Commission to implement a nature-based carbon offset programme.

2025 OUTLOOK AND GUIDANCE

- Tullow has signed a binding heads of terms agreement with Gabon Oil Company for the sale of Tullow Oil Gabon SA, for a cash consideration of $300 million net of tax. Entering into the full sale and purchase agreement is targeted for the second quarter of 2025, with completion of the transaction expected around the middle of the year, subject to relevant governmental and regulatory approvals. See separate release: LINK
- Group working interest production expected to average 50 to 55 kboepd as previously announced, including c.6 kboepd of gas.
- Ghana drilling programme with Noble Venturer to commence in May 2025, with two Jubilee wells (one producer and one water injector) expected to come onstream in the third quarter of 2025.
- Completed 4D seismic survey in first quarter of 2025 to support future well locations and drive reserves growth.

- Capital expenditure of c.$250 million, allocated as follows: c.$160 million in Ghana, c.$70 million across the west African non-operated portfolio, c.$5 million in Kenya and c.$15 million of exploration expenditure.
- Decommissioning spend of c.$15 million for UK; c.$15 million cash provisioning for Ghana and Gabon.
- Further cost base optimisation underway, with expected c.$10 million saving reducing annual cash net G&A to c.$40 million.
- Cash taxes expected to be c.$150-200 million at $70-80/bbl with payments weighted c.60% to the first half of the year.
- Forecast free cash flow of c.$100-200 million at $70-80/bbl, including c.$50 million of overdue gas receipts in Ghana from 2024.
- Refinancing of the Group's capital structure targeted during 2025, following repayment of the 2025 Notes in early March 2025.

1. Alternative performance measures are reconciled on pages 34 to 37

MANAGEMENT PRESENTATION - WEBCAST – 09:00

To access the webcast please use the following link and follow the instructions provided:

https://meetings.lumiconnect.com/100-695-362-491

A replay will be available on the website from midday on 25 March 2025:

https://www.tullowoil.com/investors/results-reports-and-presentations/

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Notes to editors

Tullow is an independent energy company that is building a better future through responsible oil and gas development in Africa. The Company's operations are focused on its West-African producing assets in Ghana, Gabon and Côte d'Ivoire, alongside a material discovered resource base in Kenya. Tullow is committed to becoming Net Zero on its Scope 1 and 2 emissions by 2030 and has a Shared Prosperity strategy that delivers lasting socio-economic benefits for its host nations. The Group is quoted on the London and Ghana stock exchanges (symbol: TLW). For further information, please refer to: www.tullowoil.com.

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CHIEF EXECUTIVE OFFICER'S REVIEW

Overview

It is a privilege to be appointed Interim Chief Executive Officer (CEO). I have been a part of Tullow since 2011 and I care deeply about the business.

I would like to thank Rahul for his leadership over the past four years. During his tenure operational performance has improved significantly and, due to a reduced cost base and rigorous capital allocation process, net debt[1] has reduced from $2.81 billion to $1.45 billion. I look forward to building on the strong foundations that have been laid by continuing to focus on delivering our transformative plans for the business in 2025 and beyond.

Key to our plans this year is the refinancing of upcoming debt maturities to strengthen our balance sheet. The process to further accelerate our deleveraging pathway continues with the strong progress towards realising the accretive cash sale of our Gabonese assets which is expected to close around the middle of the year.

In January 2025 we successfully resolved our claim in relation to the assessment of Ghana Branch Profits Remittance Tax (BPRT). This outcome, which determined that Tullow Ghana was not liable to pay the $320 million BPRT assessment previously issued by the Ghana Revenue Authority (GRA) and will have no future exposure to BPRT in respect of its operations under its Petroleum Agreements (PAs), affirmed our long held assessment and confidence in the PAs and removed a material overhang from our business. We continue to engage with the Government of Ghana on two further disputed tax claims, which were referred to the International Chamber of Commerce (ICC) in February 2023, with the aim of resolving these disputes on a mutually acceptable basis.

We have a clear plan to unlock material value from Tullow's unique pan-African platform. Tullow is a cash generative business and we are laying the foundations to grow our reserves base, accelerate our deleveraging pathway and deliver significant value accretion.

Operational performance

Our commitment to operational delivery is enabling us to manage our assets effectively. In the first half of 2024 the Ghana drilling programme was completed safely and ahead of schedule and resulted in 18 new Jubilee wells coming onstream since 2021.

2024 was a mixed year from a production perspective. Lower than anticipated production at Jubilee in the second half of 2024 was partially offset by strong performance at TEN. To address decline rates at Jubilee we have introduced a number of operational process improvements including power supply upgrades on the FPSO and measures to improve water injection reliability and increase capacity to 300 kbwpd.

Group working interest production for 2025 is expected to be 50-55 kboepd, including c.6 kboepd of gas production and inclusive of a two-week planned maintenance shutdown on the Jubilee field in the first half of the year, which will have a c.4% impact on Jubilee annual production. Two new Jubilee wells (one producer and one water injector) will be drilled, starting in May 2025, and are expected to come onstream in the third quarter of the year.

Ghana

Ghana continues to be the cornerstone of our operations. During the year, operational efficiency remained high with average facility uptime across the FPSOs averaging 97% and a combined average production rate of c.44.1 kbopd net. Five new Jubilee wells (three producers and two water injectors) were brought onstream during the first half of 2024, completing the Ghana drilling programme safely, and approximately six months ahead of schedule.

Gross oil production from the Jubilee field averaged c.87 kbopd (c.33.9 kbopd net). Production was impacted primarily by the performance of the J69 producer well, a lack of pressure communication from water injection, water injection performance and increased water cut in certain wells. The FPSO will undergo planned maintenance in the first quarter of 2025, during which we plan to implement upgrades to improve the reliability of the power supply and water injection consistency. Stable water injection combined with production optimisation activities is expected to reduce the rate of decline experienced in the second half of 2024.

Gross oil production from the TEN fields exceeded expectations, averaging c.18.5 kbopd (c.10.2 kbopd net) during the year, with Enyenra and Ntomme wells responding positively to both injection and production optimisation. We continue to explore options to maximise long term value from TEN, including a focus on the cost base to improve economics, and maturing further infill potential.

Net gas production in Ghana averaged 6.0 kboepd in 2024. The Jubilee interim Gas Sales Agreement (GSA) remains in place until the fourth quarter of 2025 at $3.00/mmbtu. We are planning to supply TEN gas during the Jubilee shutdown and continue to progress options to create a significant long-term revenue stream from the gas production and discussions continue regarding third party off-take opportunities.

Discussions with the Government of Ghana are ongoing in relation to receivables for the exported gas and we look forward to working with the new administration to settle the payments.

In 2025 we will undertake a short drilling programme in Ghana, with a primary focus on reducing natural decline. Furthermore, the state-of-the-art 4D seismic survey at the Jubilee and TEN fields will improve our understanding of the pressure and fluid movement in the reservoirs and is expected to support at least two further drilling campaigns on Jubilee within the current licence period, which will ultimately enable us to book more wells as reserves. Combined with the upward revision of TEN reserves related to substantial progress towards a material reduction in fixed costs, including in relation to the FPSO, and further 4D seismic assisted development drilling, there is a material opportunity ahead to sustain long-term production beyond the current life of field.

Non-operated and exploration portfolios

Production from the non-operated portfolio in 2024 was 10.6kbopd net. The production loss resulting from an incident at Simba was largely offset by improved production from the field when it came back onstream, as well as good performance from other onshore and offshore fields in the portfolio.

The Simba field in Gabon was shut down following an incident in March 2024 at the Perenco operated Becuna Platform, which tragically resulted in fatalities. The operator resumed operations in August 2024 after putting in place the necessary operational and engineering controls and obtaining the necessary regulatory approvals.

In Gabon, the Falcon NE infrastructure led exploration (ILX) prospect on the DE8 licence will be drilled during the first half of 2025. The Sarafina ILX well, drilled in 2024, found hydrocarbons and work is ongoing with the operator to evaluate the commercial potential.

In Côte d'Ivoire, options to realise value and mitigate capital exposure at the Espoir field are being explored ahead of licence expiry in 2026. We continue to assess options on the way forward for exploration licences CI-524 and CI-803.

In Argentina, we continue to assess options for these licences whilst mitigating capital exposure.

Decommissioning activities in the Banda/Tiof fields in Mauritania were accelerated in 2024 and have been completed ahead of schedule and below budget.

Kenya

Despite the delays associated with securing governmental approval and a strategic partner, Kenya remains a material option to drive value and growth and we are continuing to work with the Kenyan government to seek support for a Field Development Plan (FDP) and identify a long-term strategic partner, which is a key milestone to achieve a Final Investment Decision (FID).

Reserves and resources

At the end of 2024, audited 2P reserves were 164.5 mmboe (2023: 212.2 mmboe). The reserves reduction includes 22.4 mmboe of Group production during 2024 and a downward revision in Jubilee. Although recent Jubilee drilling results have encountered reservoir thicknesses close to prognosis, water has broken through in certain producing wells earlier than previously expected. This suggests that there still remain significant volumes of bypassed oil, which will be optimally targeted utilising the data produced by the 2025 4D seismic campaign. TEN reserves have been revised upwards as we progress a material reduction in fixed operating costs, especially on the FPSO, which extends the economic lifetime of the asset and facilitates further potential development through infill drilling.

Our asset base continues to have significant value, and as at 31 December 2024, the Group's audited 2P NPV10 was $2.5 billion.

The Group's audited 2C resources of 708.6 mmboe at the end of 2024 (2023: 745.0 mmboe) reflect the material opportunity we have to mature resources into reserves to realise sustained long-term production. In 2025, part of the Group's material 2C resources are expected to mature into 2P reserves with the support of the ongoing 4D seismic survey in Ghana and resulting identification of robust infill targets.

Sustainability

We are committed to building a better future through responsible oil and gas development. We recognise the ongoing need for oil and gas in Africa over the coming decades and we will continue to support our host countries to develop their natural resources whilst taking actions to minimise our environmental footprint and create value for all stakeholders including the communities where we operate.

As part of the double materiality assessment we conducted in 2024, we engaged a wide group of stakeholders to ensure we are focussed on the material economic, social and environmental impacts and issues that are most relevant to our business. We also refreshed how we communicate our sustainability approach to ensure it is clear for our stakeholders.

Our Net Zero by 2030 commitment is a core aspect of our strategy. During the year we implemented process improvements and modifications on our FPSOs in Ghana, and after all engineering works are complete, we expect routine flaring to be eliminated by the end of 2025.

As announced in July 2024, we have formed a strategic partnership with the Ghana Forestry Commission to begin full scale implementation of a nature-based carbon offset programme. This initiative aims to generate up to one million tonnes of certified carbon offsets per year to mitigate our residual, hard to abate emissions. The capability we have developed in addressing our emissions can also be applied to other carbon intensive assets across the continent to support low emission resource extraction.

Our community development programmes focused on improving education and employability in our host communities and creating opportunities for local employment and entrepreneurship. In February 2024, as part of our new 'Accelerating Progress Through Partnerships' community strategy, we announced the first multi-year Agriventures partnership with Innohub Foundation in Ghana. This two-year agriculture-focused programme will find and support entrepreneurs to set up and grow businesses capable of providing sustainable livelihoods.

To build on our existing commitment to minimise our environmental impact and protect biodiversity, in 2024 we set a "No Net Loss" nature ambition and completed a nature baseline assessment of our operated and non-operated assets to identify our nature-related impacts, risks and opportunities. In addition, we have also published our inaugural Taskforce on Nature-related Financial Disclosures (TNFD) report.

Outlook

In the year ahead our priorities are to progress our refinancing plan, optimise our production activities at Jubilee and TEN, and grow our reserve base. In particular we are leveraging advanced technologies and innovative approaches to minimise decline and extend the life of these fields and we have absolute confidence in the Jubilee field to deliver material cash flows and provide the business with optionality for returns and growth, once our net debt target of below $1 billion is reached.

The repayment of the 2025 Notes combined with our ongoing work to address our upcoming debt maturities will continue to strengthen our balance sheet.

In the near term we will maintain our focus on costs and financial discipline, prioritising high returns and focusing on investments that add value. As we continue to reduce our debt and optimise our capital structure, our balance sheet will grow stronger and we will be well-positioned to create lasting economic and social value for all stakeholders.

I would like to thank the whole Tullow team for all their hard work and dedication, they are the driving force behind the progress we have made in 2024 and they have shown tremendous resilience in recent months as we have embarked on additional cost optimisation, including redundancies associated with streamlining our cost base.

I would also like to thank our shareholders for their continued support, as we realise the potential of the business and generate value for all stakeholders.

1. Alternative performance measures are reconciled on pages 34 to 37

FINANCE REVIEW

Income Statement

Income Statement (key metrics)	2024	2023
Revenue ($m)		
Sales volume (boepd)	52,421	55,754
Realised oil price ($/bbl)	76.4	77.5
Total revenue	1,535	1,634
Operating income/(costs) ($m)		
Underlying cash operating costs [1]	(272)	(293)
Depreciation, Depletion and Amortisation (DDA) of oil and gas and leased assets	(438)	(431)
DDA before impairment charges ($/bbl)	19.6	18.8
Overlift and oil stock movements	(43)	(109)
Administrative expenses	(53)	(56)
Asset revaluation	39	–
Exploration costs written off	(213)	(27)
Impairment reversal/(Impairment) of property, plant and equipment, net	12	(408)
Gain on bond buyback	–	86
Net financing costs	(274)	(286)
Profit from continuing activities before tax	322	96
Income tax expense	(267)	(206)
Profit/(loss) for the year	55	(110)
Adjusted EBITDAX [1]	1,152	1,151
Basic earnings/(loss) per share (cents)	3.7	(7.6)

1. Alternative performance measures are reconciled on pages 34 to 37.

Revenue

Sales oil volumes

During the year, there were 52,421 boepd (2023: 55,754 boepd) of liftings. The decrease was primarily driven by a reduction of two liftings in Gabon offset by an additional 650 kbbls lifted in Ghana, with 13 cargos lifted in Jubilee (2023: 13) and 4.5 in TEN (2023: 4).

Realised oil price ($/bbl)

The Group's realised oil price after hedging for the period was $76.4/bbl (2023: $77.5/bbl) and before hedging $80.2/bbl (2023: $84.3/bbl). Lower oil prices and lower hedged volumes subject to price caps compared to 2023 have resulted in a lower hedge loss which decreased total revenue by $74 million (2023: $139 million).

Gas sales

Included in Total Revenue of $1,535 million are gas sales of $54 million of which $48 million relates to Ghana. During the year, Tullow exported 33,660 mmscf (gross) of gas at an average price of $2.97/mmbtu in Ghana.

Cost of sales

Underlying cash operating costs

Underlying cash operating costs amounted to $272 million; $12.2/boe (2023: $293 million; $12.8/boe). Routine operating costs remain largely consistent with prior year. The decrease is primarily driven by non-recurring expenditure incurred in prior year, which included costs related to TEN shutdown and Jubilee riser remediation.

Depreciation, depletion and amortisation

DDA charges before impairment on production and development assets amounted to $438 million; $19.6/boe (2023: $431 million; $18.8/boe). The increase in DDA per boe was primarily driven by the reduction in Jubilee field 2P reserves during the current year offset by the impact of TEN field impairment recorded in 2023.

Overlift and oil stock movements

The Group recognised an overlift expense of $43 million (2023: overlift expense $109 million). The decrease in overlift expense is primarily due to lower liftings in Gabon in the current year, resulting from reduced oil production volumes compared to the prior year.

Administrative expenses

Administrative expenses of $53 million (2023: $56 million) have decreased in the current year despite the inflationary environment. This is largely due to reduction in one-off corporate project expenditures in the current year. Further cost base optimisation is underway for 2025, with expected c.$10 million saving reducing annual net G&A to c.$40 million.

Asset revaluation

Asset revaluation of $39 million relates to assets disposal as part of the assets swap with Perenco in Gabon (refer to Note 11 for further information).

Exploration costs written off

During 2024, the Group wrote off exploration costs of $213 million (2023: $27 million) primarily driven by Kenya where an extension of the Field Development Plan review date to June 2025 led to a reassessment of the risks associated with reaching Final Investment Decision and resulted in a $145 million impairment (refer to Note 8 for further details). Additionally, the carrying values of assets in Argentina and Cote d'Ivoire were written off by $39 million and $16 million, respectively, due to lack of planned expenditure on licences prior to expiry. Furthermore, $10 million was written off in relation to the Sarafina well at Simba, in Gabon.

Impairment of property, plant and equipment

The Group recognised a net impairment reversal on PP&E of $12 million in the current year (2023: Net impairment of $408 million) largely driven by cost savings from operational efficiencies and scope revision in the operated Mauritania decommissioning campaign.

Net financing costs

Net financing costs for the period were $274 million (2023: $286 million). This decrease is mainly attributable to lower interest on bonds due to a reduction in the outstanding balance, partially offset by higher interest on obligations under leases.

A reconciliation of net financing costs is included in Note 6.

Taxation

The overall net tax expense of $267 million (2023: $206 million) primarily relates to tax charges in respect of the Group's production activities in West Africa, reduced by deferred tax credits associated with future UK decommissioning expenditure, exploration write-offs and impairments.

Based on a profit before tax for the period of $322 million (2023: $96 million), the effective tax rate is 83.0% (2023: 214.3%). After adjusting for non-recurring amounts related to exploration write-offs, disposals, impairments, provisions and their associated deferred tax benefit, the Group's adjusted tax rate is 60.1% (2023: 70.2%). The effective tax rate is in line with the prior year, with the impact of non-deductible expenditure in Ghana and Gabon and no UK tax benefit arising from net interest and hedging expense of $206 million (2023: $167 million) being partially offset by deferred tax credits related to non-operated assets undergoing decommissioning and prior year adjustments.

The Group's future statutory effective tax rate is sensitive to the geographic mix in which pre-tax profits arise. There is no UK tax benefit from net interest and hedging expenses, whereas net interest and hedging profits would be taxable in the UK. Consequently, the Group's tax charge will continue to vary according to the jurisdictions in which pre-tax profits occur.

Analysis of adjusted effective tax rate ($m)		Adjusted profit/(loss) before tax	Tax (expense)/credit	Adjusted effective tax rate
Ghana	2024	580.3	(208.6)	35.9%
	2023	584.4	(210.1)	35.9%
Gabon	2024	130.6	(38.2)	29.3%
	2023	216.0	(101.2)	46.8%
Corporate	2024	(281.6)	(5.7)	(2.0%)
	2023	(379.4)	9.6	2.5%
Other non-operated & exploration	2024	(7.8)	(0.7)	(8.7%)
	2023	1.5	4.7	(324.2%)
Total	**2024**	**421.5**	**(253.2)**	**60.1%**
	2023	**422.5**	**(296.9)**	**70.2%**

Adjusted EBITDAX

Adjusted EBITDAX for the year was $1,152 million (2023: $1,151 million) with a reduction in operating costs of $21 million, decrease in administrative expenses of $5 million, lower royalty taxes of $6 million and a decrease in overlift expense of $67 million, offset by lower revenue of $99 million.

Profit/(loss) for the year from continuing activities and earnings per share

The profit for the year from continuing activities amounted to $55 million (2023: $110 million loss). The increase in profit after tax was mainly driven by a reduction in impairments, recognition of asset revaluation gains and provision releases in the current year. Basic earnings per share was 3.7 cents (2023: 7.6 cents loss per share).

Balance sheet and liquidity management

Key metrics	2024	2023
Capital investment ($m)[1]	231	380
Derivative financial instruments ($m)	(12)	(35)
Borrowings ($m)	(1,976)	(2,085)
Underlying operating cash flow ($m)[1]	668	813
Free cash flow ($m)[1]	156	170
Net debt ($m)[1]	1,452	1,608
Gearing (times)[1]	1.3	1.4

1. Alternative performance measures are reconciled on pages 34 to 37.

Capital investment

Capital expenditure amounted to $231 million (2023: $380 million) with $206 million invested in production and development activities of which $134 million invested in Jubilee mainly comprising of $103 million spend on drilling costs. Investments in exploration and appraisal activities are $25 million.

The Group’s 2025 capital expenditure is expected to be c.$250 million and is expected to comprise Ghana capex of c.$160 million, West African Non-Operated capex of c.$70 million, Kenya capex of c.$5 million and exploration spend of c.$15 million.

Decommissioning

Decommissioning expenditure was $49 million in 2024 (2023: $67 million). The Group’s decommissioning budget in 2025 is c.$30 million of which c.$15 million is cash provisioning for future decommissioning in Ghana and Gabon. Subject to programme scheduling, at the end of 2025 it is expected that c.$15 million of decommissioning liabilities in the UK will remain.

Derivative financial instruments

The Group has a material hedge portfolio in place to protect against commodity price volatility and to ensure the availability of cash flow for re-investment in capital programmes that are driving business delivery.

At 31 December 2024, the Group’s hedge portfolio provides downside protection for c.60% of forecast production entitlements in the first half of 2025 with c.$59/bbl weighted average floors across all structures; while retaining strategic upside participation across for the same period, with only c.5% of forecast production entitlements capped with collars at a weighted average sold call of c.$92/bbl, and c.40% of forecast production entitlements secured with three-way collars with $92-$102/bbl call spreads. Similarly in the second half of 2025, the Group’s hedge portfolio provides downside protection for c.55% of forecast production entitlements with c.$60/bbl weighted average floors across all structures; for the same period, c.15% of forecast production entitlements is capped at weighted average sold calls of c.$89/bbl while c.30% of forecast production entitlements is secured with three-way collars.

All financial instruments that are initially recognised and subsequently measured at fair value have been classified in accordance with the hierarchy described in IFRS 13 Fair Value Measurement. Fair value is the amount for which the asset or liability could be exchanged in an arm’s length transaction at the relevant date. Where available, fair values are determined using quoted prices in active markets (Level 1). To the extent that market prices are not available, fair values are estimated by reference to market-based transactions or using standard valuation techniques for the applicable instruments and commodities involved (Level 2).

All of the Group’s derivatives are Level 2 (2023: Level 2). There were no transfers between fair value levels during the year.

At 31 December 2024, the Group’s derivative instruments had a net negative fair value of $12 million (2023: net negative $35 million).

The following table demonstrates the timing, volumes and prices of the Group’s commodity hedge portfolio at year end:

1H25 hedge portfolio at 31 December 2024	bopd	Bought put (floor)	Sold call	Bought call
Straight puts	9,500	$58.47	–	–
Collars	2,000	$60.00	$91.94	–
Three- way collars (call spread)	16,500	$59.05	$92.02	$102.02
Total/Weighted Average	**28,000**	**$58.92**	**$92.01**	**$102.02**

2H25 hedge portfolio at 31 December 2024	bopd	Bought put (floor)	Sold call	Bought call
Straight puts	4,500	$59.94	–	–
Collars	7,000	$60.00	$89.05	–
Three- way collars (call spread)	12,500	$59.20	$83.64	$93.64
Total/Weighted Average	**24,000**	**$59.57**	**$85.58**	**$93.64**

Borrowings

On 15 May 2024, the Group made the annual prepayment of $100 million of the Senior Secured Notes due 2026.

The Group's total drawn debt reduced to $2,007.4 million, consisting of $492.5 million nominal value Senior Notes due in March 2025, $1,385.2 million nominal value Senior Secured Notes due in May 2026 and $129.7 million outstanding under the Glencore facility.

Management regularly reviews options for optimising the Group's capital structure and may seek to refinance, retire or purchase any of its outstanding debt from time to time through new debt financings and/or cash purchases or exchanges in the open market, privately negotiated transactions or otherwise.

Credit ratings

The Group maintains credit ratings with Standard & Poor's (S&P's) and Moody's Investors Service (Moody's).

Since December 2023, S&P has maintained the Group's corporate credit rating at B- with negative outlook, and the rating of the 2026 Notes at B- and the rating of the 2025 Notes at CCC+. Similarly, Moody's has maintained the Group's corporate credit rating at Caa1 with negative outlook, and the rating of 2026 Notes at Caa1 and the rating of the 2025 Notes at Caa2.

Underlying operating cash flow and free cash flow

Underlying operating cash flow for the year was $668 million (2023: $813 million), reflecting a decrease of $145 million. This was primarily driven by $148 million decline in cash revenue due to lower sales volumes, impact of reduced oil prices and timing of revenue payments. Additionally, cash taxes increased by $76 million compared to the prior year. These factors were partially offset by an $25 million reduction in cash operating costs, royalty taxes and administrative expenses and $26 million decrease in lease obligation repayments.

Free cash flow for the year decreased to $156 million (2023: $170 million). Underlying operating cashflow has reduced by $145 million, as outlined above. This decrease was largely offset by lower net cash used in investing activities, as well as reduced lease payments related to capital activities and decommissioning costs, which decreased by $55 million, $32 million, and $22 million, respectively. These reductions were due to the completion of the JSE campaign in Ghana and Chinguetti decommissioning campaign in Mauritania in 2023. Additionally, finance costs paid were $17 million lower in the current period.

Net debt and gearing

Reconciliation of net debt	$m
FY 2023 net debt	**1,608.4**
Sales revenue	(1,534.9)
Operating costs	272.4
Other operating and administrative expenses	169.2
Operating cash flow before working capital movements	(1,093.3)
Movement in working capital	(25.5)
Tax paid	360.3
Purchases of intangible exploration and evaluation assets and property, plant and equipment	232.6
Other investing activities	(19.5)
Other financing activities	392.2
Foreign exchange loss on cash	(2.9)
FY 2024 net debt	**1,452.3**

Net debt reduced by $156.1 million during the year to $1,452.3 million on 31 December 2024 (2023: $1,608.4 million), due to generation of free cash flow of $156.1 million (as explained above).

The Gearing ratio has decreased to 1.3 times (2023: 1.4 times) due to the reduction in net debt compared to prior year.

Ghana tax assessments

On 24 December 2024, the BPRT Tribunal issued its ruling to the International Chamber of Commerce (ICC) which delivered its award on 2 January 2025 with regards to the BPRT arbitration with the Government of Ghana. The Tribunal determined that BPRT is not applicable to Tullow Ghana since it falls outside of the tax regime provided for in the Petroleum Agreements. This will mean that Tullow Ghana is not liable to pay the US$320 million BPRT assessment issued by the Ghana Revenue Authority and Tullow will have no future exposure to BPRT in respect of its operations under the Petroleum Agreements. Tullow has two further ongoing disputed tax assessments that relate to the disallowance of loan interest deductions for the fiscal years 2010 - 2020 and proceeds received by Tullow Oil plc under Tullow's corporate Business Interruption Insurance policy. Both were referred to international arbitration in 2023, with first hearings scheduled for 2025, however we continue to engage with the Government of Ghana, including the GRA, with the aim of resolving the assessments on a mutually acceptable basis.

Liquidity risk management and going concern

The Directors have extended the going concern assessment period to 31 May 2026, aligning with the maturity date of the 2026 senior secured bonds (2026 Notes). The Group closely monitors and manages its liquidity headroom. Cash forecasts are regularly produced, and sensitivities run for different scenarios covering key judgements and assumptions including, but not limited to, changes in commodity prices, different production rates from the Group's producing assets and different outcomes on ongoing disputes or litigation and the timing of any associated cash outflows. This assessment covers both the Group and the Company.

Management has applied the following oil price assumptions for the going concern assessment based on forward prices and market forecasts:

Base Case: $70/bbl for 2025; $70/bbl for 2026.

Low Case: $65/bbl for 2025; $65/bbl for 2026.

To consider the principal risks to the cash flow projections, a sensitivity analysis has been performed which is represented in the Low Case which management considers to be severe, but plausible, given the cumulative impact of the sensitivities applied. The most significant risk would be a sustained decline in oil prices. The analysis has been stress tested by including a 10% production decrease and 5% increased operating costs compared to the Base Case. Management has also considered additional outflows in respect of all ongoing litigations/arbitrations within the Low Case, with an additional $67 million outflow being included for the cases expected to progress in the going concern period. Based on the legal opinions received by management, the remaining arbitration cases are not expected to conclude within the going concern period or have remote outcomes, therefore no outflows have been included in that respect in the Low Case. In the event of negative outcomes after the going concern period, management would use all available court processes to appeal such rulings which, based on observable court timelines, would likely take in excess of a further year.

The Group is reliant on the continued provision of external financing. The undrawn $250 million revolving credit facility (RCF) and the $1.3 billion 2026 Notes fall due within the going concern period and both will require refinancing to ensure the Group has sufficient liquidity to meet its financial obligations. The Directors intend to complete a holistic refinancing of the existing debt capital structure during 2025. Discussions with banks and commodity traders to secure the refinancing are underway. A fundamental assumption in concluding that the Group is a going concern is a successful execution of a holistic refinancing. The successful execution of a holistic refinancing is subject to favourable macroeconomic and market conditions including but not limited to oil price, credit ratings and accessibility of High Yield Bond markets and is therefore outside the control of management.

In addition, a binding heads of terms agreement for the sale of Tullow Oil Gabon SA which holds 100% of Tullow's working interest in Gabon for cash consideration of $300 million net of tax has been entered into with Gabon Oil Company. Signing of a sale and purchase agreement is targeted for the second quarter of 2025. Completion of the transaction, which will be subject to relevant governmental and regulatory approvals, and receipt of the associated cash proceeds are assumed in June 2025 in the Base Case, with a three month delay assumed in the Low Case. Completion of this transaction will materially reduce the Group's net debt and is therefore expected to reduce the risk associated with the holistic debt refinancing. However, completion and timing of completion of this transaction are outside the control of management.

Implications and material uncertainties

The Base Case and the Low Case scenarios forecast a liquidity shortfall in May 2026 when the $1.3 billion 2026 Notes become due for payment, unless the Directors execute a holistic refinancing of the Group's debt capital structure in advance of that date. In addition, the Low Case scenario forecasts a liquidity shortfall at the end of June 2025, following expiry of the RCF and due to the assumed delay to the receipt of proceeds from the sale of Tullow Oil Gabon SA.

The Directors have initiated a process to execute a holistic refinancing based on proposals received from banks. The Directors believe this is achievable before the end of June 2025, noting the risks associated with wider market conditions. If this were not achieved by the end of June 2025 the Directors would continue to pursue such a refinancing in the second half of 2025 to alleviate the projected liquidity shortfall in May 2026 and believe this is achievable, again subject to market conditions.

In addition, if a holistic refinancing was not executed by the of June 2025 and receipt of proceeds from the sale of Tullow Oil Gabon SA was delayed (as assumed in the Low Case scenario), the Directors plan to enter into discussions with the lenders under the RCF to extend the maturity of the facility to align with the timing of completion of the holistic refinancing or the receipt of proceeds from the sale of Tullow Oil Gabon SA. Should this not be possible, the Directors will pursue alternative bridge financing from commodity traders or secure an alternative source of financing from private credit markets ahead of the projected shortfall at the end of June 2025. The Directors have received unsolicited offers of credit from such counterparties in excess of the need to alleviate the projected shortfall and would seek to engage with them and progress such offers, if required.

The Directors note that despite expressions of interest from private as well as public parties for participation in the holistic debt refinancing, implementing a holistic refinancing is outside the control of the Group. If the Directors were unable to implement a refinancing proposal, the ability of the Group to continue trading would depend upon the Group being able to negotiate a financial restructuring proposal with its creditors and, if necessary, that proposal being approved by shareholders. Whilst the Board would seek to negotiate such a financial restructuring proposal with its creditors, it is possible that the creditors would not engage with the Board in those circumstances. There would therefore be a possible risk of the Group entering into insolvency proceedings, which the Directors consider would likely result in limited or no value being returned to shareholders.

The Directors have concluded that 1) implementing a holistic refinancing by the end June 2025 or by May 2026 at the latest and 2) obtaining sufficient liquidity to cover the expiration of the RCF at the end of June 2025, if a holistic refinancing is not implemented by that date, by extending the maturity of the facility or by completing the sale of Tullow Oil Gabon SA and receipt of proceeds from the transaction or with alternative bridge financing, are outside the control of the Group. These are therefore material uncertainties that may cast significant doubt over the Group and the Company's ability to continue as a going concern. Notwithstanding these material uncertainties, the Board has confidence in the Group's ability to implement a holistic refinancing or extend the RCF or either complete the sale of Tullow Oil Gabon SA including receipt of proceeds or seek an alternative source of financing before the end of June 2025. This is based on the plans in place on the holistic refinancing, the ongoing support of existing lenders under the RCF, the binding heads of terms agreement signed with Gabon Oil Company for the sale of Tullow Oil Gabon SA and the unsolicited offers of liquidity received from other sources of finance and credit providers. This is in the context of the underlying value and cash generation of the Group's producing fields to support future debt service and repayment. On this basis the Board have prepared the Financial Statements on a going concern basis. The Financial Statements do not include the adjustments that would result if the Group and the Company were unable to continue as a going concern.

Events since 31 December 2024

On 14 February 2025, Richard Miller was appointed as Interim Chief Executive Officer (CEO). Rahul Dhir stepped down as Director from the Board of Tullow Oil plc.

On 3 March 2025, the Group settled the 2025 Notes upon maturity with a payment of $510 million, comprising a $493 million principal repayment and $17 million final coupon. This payment was partially funded through a $270 million drawdown from the Secured Notes Facility, with the remainder sourced from cash at bank. Following the $270 million drawdown, the Secured Notes Facility was fully drawn at $400 million.

On 24 March 2025, Tullow announced that it had signed a binding heads of terms agreement with Gabon Oil Company for the sale of Tullow Oil Gabon SA, which holds 100% of Tullow's working interests in Gabon for a total cash consideration of $300 million net of tax. Signing of a sale and purchase agreement is targeted for the second quarter of 2025, with completion of the transaction and receipt of funds expected around the middle of the year, subject to receipt of relevant governmental and regulatory approvals.

The transaction is a corporate sale of Tullow's entire Gabonese portfolio of assets, representing c.10 kbopd of 2025 production guidance and c.36 million barrels of 2P reserves. Conditions precedent for the completion of the Transaction include all necessary approvals (including from government ministries), CEMAC Competition Commission approval and Tullow's processing of the 2024 dividend in compliance with Gabonese requirements.

This is a non adjusting event as at 31 December 2024 as defined by IAS 10 'Events after the Reporting Period'.

There have not been any other events since 31 December 2024 that have resulted in a material impact on the year end results.

Group income statement

Year ended 31 December 2024

$m	Notes	2024	2023
Revenue		1,534.9	1,634.1
Cost of sales	5	(780.9)	(869.2)
Gross profit		**754.0**	**764.9**
Administrative expenses	5	(53.2)	(56.1)
Restructuring provisions	5	(7.1)	–
Expected credit loss charge on trade receivables		(6.6)	–
Other gains		–	0.2
Asset revaluation	11	38.9	–
Exploration costs written off	8	(212.6)	(27.0)
Impairment reversal/(impairment) of property, plant and equipment, net	9	11.8	(408.1)
Provisions reversal	5	70.4	22.0
Operating profit		**595.6**	**295.9**
Loss on hedging instruments		–	(0.4)
Gain on bond buyback		–	86.0
Finance income	6	71.5	44.0
Finance costs	6	(345.6)	(329.6)
Profit from continuing activities before tax		**321.5**	**95.9**
Income tax expense	7	(266.9)	(205.5)
Profit/(loss) for the year from continuing activities		**54.6**	**(109.6)**
Attributable to			
Owners of the Company		54.6	(109.6)
Earnings/(loss) per ordinary share from continuing activities		¢	¢
Basic		3.7	(7.6)
Diluted		3.6	(7.6)

Group statement of comprehensive income and expense

Year ended 31 December 2024

$m	2024	2023
Profit/(loss) for the year	54.6	(109.6)
Items that may be reclassified to the income statement in subsequent periods		
Cash flow hedges		
(Losses)/gains arising in the year	(28.5)	20.1
(Losses)/gains arising in the year – time value	(21.9)	50.3
Reclassification adjustments for items included in profit on realisation	47.5	111.3
Reclassification adjustments for items included in loss on realisation – time value	26.1	27.8
Exchange differences on translation of foreign operations	2.0	(5.8)
Net other comprehensive income for the year	25.2	203.7
Total comprehensive income for the year	**79.8**	**94.1**
Attributable to		
Owners of the Company	79.8	94.1

Group balance sheet

As at 31 December 2024

$m	Notes	2024	2023
Assets			
Non-current asset			
Goodwill	11	44.9	–
Intangible exploration and evaluation assets	8	109.1	287.0
Property, plant and equipment	9	2,324.1	2,532.8
Other non-current assets	10	340.8	338.6
Deferred tax assets		8.3	19.6
		2,827.2	3,178.0
Current assets			
Inventories		132.4	107.3
Trade receivables		137.9	43.5
Other current assets	10	391.9	571.2
Current tax assets		6.9	3.8
Derivative financial instruments		0.1	–
Cash and cash equivalents		555.1	499.0
Assets classified as held for sale	11	–	55.8
		1,224.3	1,280.6
Total assets		**4,051.5**	**4,458.6**
Liabilities			
Current liabilities			
Trade and other payables	12	(736.5)	(775.0)
Borrowings		(589.4)	(100.0)
Provisions	14	(24.3)	(67.9)
Current tax liabilities		(175.3)	(230.5)
Derivative financial instruments		(11.9)	(35.0)
Liabilities associated with assets classified as held for sale	11	–	(17.6)
		(1,537.4)	(1,226.0)
Non-current liabilities			
Trade and other payables	12	(665.9)	(783.2)
Borrowings		(1,386.4)	(1,984.6)
Provisions	14	(321.5)	(403.7)
Deferred tax liabilities		(413.0)	(420.5)
		(2,786.8)	(3,592.0)
Total liabilities		**(4,324.2)**	**(4,818.0)**
Net liabilities		**(272.7)**	**(359.4)**
Equity			
Called-up share capital		217.5	216.7
Share premium		1,294.7	1,294.7
Foreign currency translation reserve		(242.4)	(244.4)
Hedge reserve		0.1	(18.9)
Hedge reserve – time value		(12.1)	(16.3)
Merger reserve		755.2	755.2
Retained earnings		(2,285.7)	(2,346.4)
Equity attributable to equity holders of the Company		(272.7)	(359.4)
Total equity		**(272.7)**	**(359.4)**

Group statement of changes in equity

Year ended 31 December 2024

$m	Share capital	Share premium	Foreign currency translation reserve[1]	Hedge reserve[2]	Hedge reserve – time value[2]	Merger reserve[3]	Retained earnings	Total
At 1 January 2023	215.2	1,294.7	(238.6)	(150.3)	(94.4)	755.2	(2,241.3)	(459.5)
Profit for the period	–	–	–	–	–	–	(109.6)	(109.6)
Hedges, net of tax	–	–	–	131.4	78.1	–	–	209.5
Currency translation adjustments	–	–	(5.8)	–	–	–	–	(5.8)
Total comprehensive income	–	–	(5.8)	131.4	78.1	–	(109.6)	94.1
Exercise of employee share options	1.5	–	–	–	–	–	(1.5)	–
Share-based payment charges	–	–	–	–	–	–	6.0	6.0
At 1 January 2024	216.7	1,294.7	(244.4)	(18.9)	(16.3)	755.2	(2,346.4)	(359.4)
Profit for the period	–	–	–	–	–	–	54.6	54.6
Hedges, net of tax	–	–	–	19.0	4.2	–	–	23.2
Currency translation adjustments	–	–	2.0	–	–	–	–	2.0
Total comprehensive income	–	–	2.0	19.0	4.2	–	54.6	79.8
Exercise of employee share options	0.8	–	–	–	–	–	(0.8)	–
Share-based payment charges	–	–	–	–	–	–	6.9	6.9
At 31 December 2024	217.5	1,294.7	(242.4)	0.1	(12.1)	755.2	(2,285.7)	(272.7)

1. The foreign currency translation reserve represents exchange gains and losses arising on translation of foreign currency subsidiaries, monetary items receivable from or payable to a foreign operation for which settlement is neither planned nor likely to occur, which form part of the net investment in a foreign operation.
2. The hedge reserve represents gains and losses on derivatives classified as effective cash flow hedges.
3. The merger reserve represents the premium on shares issued in relation to acquisitions.

Group cash flow statement

Year ended 31 December 2024

$m	Notes	2024	2023
Cash flows from operating activities			
Profit from continuing activities before tax		321.5	95.9
Adjustments for:			
Depreciation, depletion and amortisation	9	444.2	436.6
Asset revaluation	11	(38.9)	–
Other gains		–	(0.2)
Taxes paid in kind	7	(6.3)	(11.0)
Exploration costs written off	8	212.6	27.0
Impairment (reversal)/impairment of property, plant and equipment, net	9	(11.8)	408.1
Provisions reversal		(63.3)	(22.0)
Payment for provisions	14	(0.7)	(0.6)
Decommissioning expenditure	14	(45.0)	(78.1)
Share-based payment charge		6.9	6.0
Loss on hedging instruments		–	0.4
Gain on bond buyback		–	(86.0)
Finance income	6	(71.5)	(44.0)
Finance costs	6	345.6	329.6
Operating cash flow before working capital movements		1,093.3	1,061.7
Decrease/(increase) in trade and other receivables		0.7	(36.3)
(Increase)/decrease in inventories		(25.1)	66.6
Increase in trade payables		49.9	58.7
Cash generated from operating activities		1,118.8	1,150.7
Income taxes paid		(360.3)	(274.5)
Net cash from operating activities		758.5	876.2
Cash flows from investing activities			
Proceeds from disposals		–	0.7
Purchase of additional interests in a joint operation		(8.1)	–
Purchase of intangible exploration and evaluation assets		(27.8)	(30.2)
Purchase of property, plant and equipment		(196.7)	(262.3)
Interest received		19.5	23.3
Net cash used in investing activities		(213.1)	(268.5)
Cash flows from financing activities			
Debt arrangement fees		–	(5.0)
Repayment of borrowings		(100.0)	(432.2)
Drawdown of borrowings		–	129.7
Payment of obligations under leases	13	(169.0)	(195.0)
Finance costs paid		(223.2)	(240.0)
Net cash used in financing activities		(492.2)	(742.5)
Net increase/(decrease) in cash and cash equivalents		53.2	(134.8)
Cash and cash equivalents at beginning of year		499.0	636.3
Foreign exchange gain/(loss)		2.9	(2.5)
Cash and cash equivalents at end of year		555.1	499.0

NOTES TO THE FINANCIAL STATEMENTS

Year ended 31 December 2024

1. Basis of preparation and presentation of financial information

The Financial Statements have been prepared in accordance with United Kingdom adopted international accounting standards (UK-adopted IFRSs) and International Financial Reporting Standards adopted pursuant to Regulation (EC) No. 1606/2002 as it applies in the European Union. The financial reporting framework that has been applied in the preparation of the Parent Company Financial Statements is applicable law and United Kingdom Accounting Standards, including FRS 101 Reduced Disclosure Framework (United Kingdom Generally Accepted Accounting Practice).

The financial information for the year ended 31 December 2024 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 2023 have been delivered to the Registrar of Companies and those for 2024 will be delivered following the Company’s annual general meeting. The auditor’s report on these accounts was unqualified, did not include a reference to any 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 Financial Statements have been prepared on the historical cost basis, except for derivative financial instruments and contingent consideration, which have been measured at fair value which are carried at fair value less cost to sell. The Financial Statements are presented in US dollars and all values are rounded to the nearest $0.1 million, except where otherwise stated.

The accounting policies applied are consistent with those adopted and disclosed in the Group’s Financial Statements for the year ended 31 December 2023. There have been a number of amendments to accounting standards and new interpretations issued by the International Accounting Standards Board which were applicable from 1 January 2024, however, these have not any impact on the accounting policies, methods of computation or presentation applied by the Group. Further details on new International Financial Reporting Standards adopted will be disclosed in the 2024 Annual Report and Accounts.

Certain new accounting standards and interpretations have been published that are not mandatory for 31 December 2024 reporting periods and have not been early adopted by the Group. These standards are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

2. Earnings/(loss) per ordinary share

Basic earnings/(loss) per ordinary share amounts are calculated by dividing net profit/(loss) for the year attributable to ordinary equity holders of the Parent by the weighted average number of ordinary shares outstanding during the year.

Diluted earnings per ordinary share amounts are calculated by dividing net profit/(loss) for the year attributable to ordinary equity holders of the Parent by the weighted average number of ordinary shares outstanding during the year plus the weighted average number of dilutive ordinary shares that would be issued if employee and other share options were converted into ordinary shares.

3. 2024 Annual Report and Accounts

The 2024 Annual Report and Accounts will be mailed in April 2025 only to those shareholders who have elected to receive it. Otherwise, shareholders will be notified that the Annual Report and Accounts are available on the Group’s website (www.tullowoil.com). Copies of the Annual Report and Accounts will also be available from the Company’s registered office at Building 9, Chiswick Park, 566 Chiswick High Road, London, W4 5XT.

4. Segmental Reporting

The information reported to the Group's Interim Chief Executive Officer for the purposes of resource allocation and assessment of segment performance is focused on four Business Units: Ghana, non-operated producing assets and decommissioning assets, Kenya and Exploration. Therefore, the Group's reportable segments under IFRS 8 are Ghana, Non-Operated, Kenya and Exploration.

The following tables present revenue, profit and certain asset and liability information regarding the Group's reportable business segments for the years ended 31 December 2024 and 31 December 2023.

$m	Ghana	Non-Operated	Kenya	Exploration	Corporate	Total
2024						
Sales revenue by origin	1,325.4	283.1	–	–	(73.6)	1,534.9
Segment result[1]	722.6	123.5	(145.4)	(55.9)	(91.6)	553.2
Provisions reversal						70.4
Asset revaluation						38.9
Unallocated corporate expenses[2]						(66.9)
Operating profit						595.6
Finance income						71.5
Finance costs						(345.6)
Profit before tax						321.5
Income tax expense						(266.9)
Profit after tax						54.6
Total assets	3,164.3	305.0	112.2	4.9	465.1	4,051.5
Total liabilities[3]	(1,978.4)	(254.2)	(5.8)	(6.2)	(2,079.6)	(4,324.2)
Other segment information						
Capital expenditure:						
Property, plant and equipment	126.4	122.3	2.2	–	2.6	253.5
Intangible exploration and evaluation assets	0.2	14.3	6.4	13.8	–	34.7
Depletion, depreciation and amortization	(401.4)	(37.0)	(2.7)	–	(3.1)	(444.2)
Impairment reversal of property, plant and equipment, net	–	11.8	–	–	–	11.8
Exploration costs written off	–	(11.2)	(145.4)	(56.0)	–	(212.6)

1. Segment result is a non-IFRS measure which includes gross profit, exploration costs written off and impairment of property, plant and equipment. See reconciliation below.
2. Unallocated expenditure includes amounts of a corporate nature and not specifically attributable to a geographic area.
3. Total liabilities – Corporate comprise the Group's external debt and other non-attributable liabilities.

Reconciliation of segment result

$m	2024	2023
Segment result	553.2	329.8
Add back		
Exploration costs written off	212.6	27.0
Impairment (reversal)/Impairment of property, plant and equipment	(11.8)	408.1
Gross profit	754.0	764.9

4. Segmental reporting continued

$m	Ghana	Non-Operated	Kenya	Exploration	Corporate	Total
2023						
Sales revenue by origin	1,311.4	461.8	–	–	(139.1)	1,634.1
Segment result[1]	408.2	114.0	(17.9)	(9.9)	(164.6)	329.8
Other provisions						22.0
Other gains						0.2
Unallocated corporate expenses[2]						(56.1)
Operating profit						295.9
Loss on hedging instruments						(0.4)
Gain on bond buyback						86.0
Finance income						44.0
Finance costs						(329.6)
Profit before tax						95.9
Income tax expense						(205.5)
Profit after tax						(109.6)
Total assets	3,529.7	200.9	253.3	48.5	426.2	4,458.6
Total liabilities[3]	(2,231.6)	(355.1)	(10.3)	(2.9)	(2,218.1)	(4,818.0)
Other segment information						
Capital expenditure:						
Property, plant and equipment	413.7	85.9	(2.2)	–	2.1	499.5
Intangible exploration and evaluation assets	0.2	1.6	7.5	16.1	–	25.4
Depletion, depreciation and amortisation	(387.7)	(44.1)	0.6	–	(5.4)	(436.6)
Impairment of property, plant and equipment, net	(301.2)	(97.9)	–	–	(9.0)	(408.1)
Exploration costs written off	(0.2)	0.9	(17.9)	(9.8)	–	(27.0)

1. Segment result is a non-IFRS measure which includes gross profit, exploration costs written off and impairment of property, plant and equipment. See reconciliation above.
2. Unallocated expenditure includes amounts of a corporate nature and not specifically attributable to a geographic area.
3. Total liabilities - Corporate comprise of the Group's external debt, derivative financial instruments and other non-attributable liabilities.

5. Other costs

$m	2024	2023
Cost of sales		
Operating costs	272.4	292.9
Depletion and amortisation of oil and gas and leased assets[1]	437.6	430.8
Overlift, underlift and oil stock movements	42.5	109.3
Royalties	27.9	33.9
Share-based payment charge included in cost of sales	0.4	0.4
Other cost of sales	0.1	1.9
Total cost of sales	**780.9**	**869.2**
Administrative expenses		
Share-based payment charge included in administrative expenses	6.5	5.6
Depreciation of other fixed assets	6.6	5.8
Other administrative costs	40.1	44.7
Total administrative expenses	**53.2**	**56.1**
Provisions reversal[2]	(63.3)	(22.0)

1. Depreciation expense on leased assets of $91.4 million (2023: $81.4 million) as per Note 9 includes a charge of $4.1 million (2023: $2.2 million) on leased administrative assets, which is presented in administrative expenses in the income statement. The remaining balance of $87.3 million (2023: $79.2 million) relates to other leased assets and is included in cost of sales.
2. This includes reduction in other provisions of $70.4 million (2023: $22.0 million) as well as provision for restructuring and redundancy costs of $7.1 million (2023: $nil).

The decrease in other administrative costs is mainly due to a reduction in one-off corporate project expenditure and lower insurance premiums partly offset by higher payroll costs in the current year.

6. Net financing costs

$m	2024	2023
Interest on bank overdrafts and borrowings	211.5	237.0
Interest on obligations for leases	119.7	78.6
Total borrowing costs	**331.2**	**315.6**
Finance and arrangement fees	3.0	1.9
Other interest expense	–	2.0
Unwinding of discount on decommissioning provisions	11.4	10.1
Total finance costs	**345.6**	**329.6**
Interest income on amounts due from Joint Venture partners for leases	(48.1)	(30.1)
Other finance income	(23.4)	(13.9)
Total finance income	**(71.5)**	**(44.0)**
Net financing costs	274.1	285.6

7. Taxation on profit on continuing activities

$m	2024	2023
Current tax on profits for the year		
UK corporation tax	–	(1.9)
Foreign tax	307.6	322.2
Taxes paid in kind under Production Sharing Contracts	6.3	11.0
Adjustments in respect of prior periods	(3.5)	10.8
Total corporate tax	**310.4**	**342.1**
UK petroleum revenue tax	(2.4)	(0.7)
Total current tax	**308.0**	**341.4**
Deferred tax		
Origination and reversal of temporary differences		
UK corporation tax	(19.1)	(22.9)
Foreign tax	(27.0)	(106.5)
Adjustments in respect of prior periods	1.1	(2.8)
Total deferred corporate tax	**(45.0)**	**(132.2)**
Deferred UK petroleum revenue tax	3.9	(3.7)
Total deferred tax	**(41.1)**	**(135.9)**
Total income tax expense	**266.9**	**205.5**

$m	2024	2023
Profit from continuing activities before tax	321.5	95.9
Tax on profit from continuing activities at the standard UK corporation tax rate of 25% (2023: 23.5%)	80.4	22.5
Effects of:		
Non-deductible exploration expenditure	50.3	3.4
Other non-deductible expenses	0.4	35.4
Net deferred tax asset not recognised	78.2	65.1
Utilisation of tax losses not previously recognised	(0.6)	(0.2)
Adjustment relating to prior years	(2.4)	(2.8)
Other tax rates applicable outside the UK	95.9	82.4
Other income not subject to corporation tax	0.3	(0.3)
Tax impact of acquisitions and disposals	(35.6)	–
Total income tax expense for the year	**266.9**	**205.5**

Uncertain tax treatments

The Group is subject to various material claims which arise in the ordinary course of its business in various jurisdictions, including cost recovery claims, claims from regulatory bodies and both corporate income tax and indirect tax claims. The Group is in formal dispute proceedings regarding a number of these tax claims. The resolution of tax positions, through negotiation with the relevant tax authorities or litigation, can take several years to complete. In assessing whether these claims should be provided for in the Financial Statements, management has considered them in the context of the applicable laws and relevant contracts for the countries concerned. Management has applied judgement in assessing the likely outcome of the claims and has estimated the financial impact based on external tax and legal advice and prior experience of such claims.

Provisions of $80.8 million (2023: $85.0 million) are included in income tax payable of $79.0 million (2023: $78.3 million), deferred tax liability of $nil (2023: $nil), and provisions of $1.8 million (2023: $6.7 million). Where these matters relate to expenditure which is capitalised within intangible exploration and evaluation assets and property, plant and equipment, any difference between the amounts accrued and the amounts settled is capitalised in the relevant asset balance, subject to applicable impairment indicators. Where these matters relate to producing activities or historical issues, any differences between the accrued and settled amounts are taken to the Group income statement.

Due to the uncertainty of such tax items, it is possible that on conclusion of an open tax matter at a future date, the outcome may differ significantly from management's estimate. If the Group was unsuccessful in defending itself from all these claims, the result would be additional liabilities of $608.7 million (2023: $1,030.3 million) excluding interest and penalties which in management's view are remote.

7. Taxation on profit on continuing activities continued

The provisions and contingent liabilities relating to these disputes have decreased following the conclusion of tax authority challenges and matters lapsing under the statute of limitations, but have increased, following new claims being initiated and extrapolation of exposures through to 31 December 2024, giving rise to an overall decrease in provision of $4.2 million and decrease in contingent liability of $421.6 million.

Ghana tax assessments

In October 2021, Tullow Ghana Limited (TGL) filed a Request for Arbitration with the International Chamber of Commerce (ICC) disputing the $320.3 million branch profits remittance tax (BPRT) assessment issued as part of the direct tax audit for the financial years 2014 to 2016. The Ghana Revenue Authority (GRA) is seeking to apply BPRT under a law which the Group considers is not applicable to TGL, since it falls outside the tax regime provided for in the Petroleum Agreements and relevant double tax treaties. Two hearings took place in November 2023 and June 2024. On 24 December 2024, the BPRT Tribunal issued its ruling to the ICC, which delivered its award on 2 January 2025 with regard to the BPRT arbitration with the Government of Ghana. The Tribunal determined that BPRT is not applicable to Tullow Ghana since it falls outside the tax regime provided for in the Petroleum Agreements. This means that Tullow Ghana is not liable to pay the $320.3 million BPRT assessment issued by the GRA, and Tullow has no future exposure to BPRT in respect of its operations under the Petroleum Agreements.

In December 2022, TGL received a $190.5 million corporate income tax assessment and payment demand from the GRA relating to the disallowance of loan interest for the financial years 2010 to 2020. The Group has previously disclosed assessments by the GRA relating to the same issue; this revised assessment supersedes all previous claims. The Group considers the assessment to breach TGL's rights under its Petroleum Agreements. In February 2023, TGL filed a Request for Arbitration with the ICC disputing the assessment, with the suspension of TGL's obligation to pay any amount in relation to the assessment until the dispute is formally resolved. The parties have agreed a procedural timetable for the arbitration under which the first Tribunal hearing will be held in July 2025.

In December 2022, TGL received a $196.5 million corporate income tax assessment and payment demand from the GRA relating to proceeds received by Tullow during the financial years 2016 to 2019 under Tullow's corporate Business Interruption Insurance policy. The Group considers the assessment to breach TGL's rights under its Petroleum Agreements. In February 2023, TGL filed a Request for Arbitration to the ICC disputing the assessment, with the suspension of TGL's obligation to pay any amount in relation to the assessment until the dispute is formally resolved. The parties have agreed a procedural timetable for the arbitration under which the first Tribunal hearing will be held in November 2025.

The Group continues to engage with the Government of Ghana with the aim of resolving these tax disputes on a mutually acceptable basis.

Bangladesh litigation

The National Board of Revenue (NBR) is seeking to disallow $118 million of tax relief in respect of development costs incurred by Tullow Bangladesh Limited (TBL). The NBR subsequently issued a payment demand to TBL in February 2020 for Taka 3,094 million (c$29.3 million) requesting payment by 15 March 2020. However, under the Production Sharing Contract (PSC), the Government is required to indemnify TBL against all taxes levied by any public authority, and the share of production paid to Petrobangla (PB), Bangladesh's national oil company, is deemed to include all taxes due, which PB is then obliged to pay to the NBR. TBL sent the payment demand to PB and the Government requesting the payment or discharge of the payment demand under their respective PSC indemnities. On 14 June 2021, TBL issued a formal notice of dispute under the PSC to the Government and PB. A further request for payment was received from NBR on 28 October 2021 demanding settlement by 15 November 2021. Arbitration proceedings were initiated under the PSC on 29 December 2021, and a hearing of the merits of the case were heard by the Tribunal on 20 May 2024. Final written submissions were made to the Tribunal in September 2024.

Other items

Other items totalling $192.3 million (2023: $294.0 million) comprise exposures in respect of claims for corporation tax from disallowed expenditure or withholding taxes that are either currently under discussion with the tax authorities or which arise from known issues for periods not yet under audit.

Timing of cash-flows

While it is not possible to estimate the timing and amount of tax cash flows in relation to possible outcomes with certainty, management anticipates that there will not be material cash taxes paid in excess of the amounts provided for uncertain tax treatments.

8. Intangible exploration and evaluation assets

$m	2024	2023
At 1 January	287.0	288.6
Additions	34.7	25.4
Exploration costs written off	(212.6)	(27.0)
At 31 December	109.1	287.0

The below table provides a summary of the exploration costs written off on a pre-tax basis by country.

Country	CGU	Rationale for 2024 write-off	2024 Write-off $m	2024 Remaining recoverable amount $m
Argentina	MLO114, MLO119 and MLO122	a	38.8	–
Côte d'Ivoire	Block 524 and Block 803	a	15.5	–
Gabon	Simba	b	10.3	–
Kenya	Blocks 10BB and 13T	c	145.4	103.2
New Ventures	Various	d	1.3	–
Uganda	Exploration areas 1, 1A, 2 and 3A	e	0.8	–
Other	Various		0.5	–
Total write-off			212.6	

a. No further activity planned following unsuccessful farm-down efforts.
b. Uncommercial well costs written off.
c. Delay in farm-down and extension of Field Development Plan review period.
d. New Ventures expenditure is written off as incurred.
e. Indirect tax movement on previously disposed or written-off assets.

Country	CGU	Rationale for 2023 write-off/(back)	2023 Write-off/(back) $m	2023 Remaining recoverable amount $m
Guyana	Kanuku	a	1.7	–
Guyana	Orinduik	a	0.7	–
Côte d'Ivoire	Block 524	a	3.3	–
Kenya	Blocks 10BB and 13T	b,c	17.9	242.2
New Ventures	Various	d	4.1	–
Uganda	Exploration areas 1, 1A, 2 and 3A	e	(4.3)	–
Gabon	DE8	f	3.4	–
Other	Various		0.2	–
Total write-off			27.0	

a. Current year expenditure on assets previously written off.
b. Following VIU assessment subsequent to withdrawal of JV Partners.
c. Revision of short-, medium- and long-term oil price assumptions.
d. New Ventures expenditure is written off as incurred.
e. Release of indirect tax provision following settlement.
f. Unsuccessful well costs written off.

8. Intangible exploration and evaluation assets continued

Kenya:

Discussions with the Government of Kenya (GoK) on approval of the Field Development Plan (FDP) have been ongoing since its submission on 10 December 2021. An updated FDP was submitted on 3 March 2023 and is being reviewed by the GoK before ratification by the Kenyan Parliament. Energy and Petroleum Regulatory Authority (EPRA), the regulator, has engaged third-party consultants to review the revised FDP and the current review period was extended to 30 June 2025. The review of the FDP by EPRA is progressing, and Tullow is in discussions to respond to commercial and technical queries raised as part of the review. The Group expects a production licence to be granted once the reviews are completed.

On 22 May 2023, Africa Oil Corporation (AOC) and Total Energies (TE) gave notice of their respective withdrawal from the Blocks 10BA, 10BB and 13T Production Sharing Contracts (PSCs) and the Joint Operating Agreements (JOAs), effective 30 June 2023, quoting differing internal strategic objectives as reasons. The withdrawal is ultimately subject to the GoK's consent, at which stage the withdrawal will be considered completed and Tullow will have full assignment of rights and liabilities under the JOA. Pending GoK approval, per the terms of the agreement, the participating interest (PI) vests in trust for the sole and exclusive benefit of Tullow, which is the only remaining Joint Venture Partner.

In the Tullow management's view, in light of public statements and announcements made by AOC and TE to this effect and in accordance with the terms of the JOA, it is considered that the ownership of the 50% held by AOC and TE was irrevocably passed to Tullow on 30 June 2023. From the date, Tullow has the right to benefit from the PI and will also be liable for all costs incurred going forward (except those for which the withdrawing parties remain liable for). Tullow has also obtained an external legal opinion, which substantiates the above position, however, subject to customary conditions of Tullow having the financial and technical capacity as required under the Petroleum Act. Tullow has submitted an application to GoK to obtain its approval to execute the transfer of the 50% interest and is still in discussions with EPRA/GoK to address certain commercial and technical points raised in 2H 2024 as part of the approval process.

To achieve a Final Investment Decision (FID), securing a strategic partner who will bring requisite commercial and technical abilities is a key milestone. Considering the delay in securing a farm-down offer and time taken to secure GoK approvals for transfer of the additional 50% interest, an impairment trigger was identified for 31 December 2024 reporting.

In line with the accounting policy, recoverable value was determined using a discount cash flow model. The long-term oil price assumptions remain consistent with those used at the end of 2023, while discount rates have increased by 1%. The cash flows were discounted using a pre-tax nominal discount rate of 21% (2023: 20%). This resulted in a net present value (NPV) significantly more than the carrying value of $248.6 million. However, the Group has identified the following uncertainties in respect of its ability to realise the NPV: receiving and subsequently finalising an acceptable offer from a strategic partner thus enabling FDP approval; obtaining financing for the project; and government deliverables in form of the provision of required infrastructure and fiscal terms. These items require satisfactory resolution before the Group can take an FID. The Group continues to progress with the farm-down process.

Due to the binary nature of these uncertainties, the Group was unable to either adjust the cash flows or discount rate appropriately. It has therefore used its judgement and assessed a probability of achieving FID and therefore the recognition of commercial reserves. This probability was applied to the unrisked NPV to determine a risk-adjusted recoverable value, which was then compared against the net book value of the asset. Certain risks have increased since 31 December 2023, predominantly around achieving a farm-down and receiving government approval for the FDP and the transfer of the additional 50% PI. Tullow continues to receive expressions of interest and non binding offers from potential strategic partners and is in active discussions with multiple interested parties. Hence the recoverable amount based on risked NPV has been revised to $103.2 million and a further impairment of $145.4 million has been recognised in the year ended 31 December 2024.

Management has compared the remaining net book value of the Kenya project with the recoverable value under alternative development options, in case the farm-down based on the FDP is unsuccessful. The alternative development options support the recognition of the remaining net book value of the Kenya project and will be pursued if the current project development plan could not be progressed further.

Should the uncertainties around the project be resolved, there will be a reversal from the previously recorded impairment charges of up to $1,075.2 million. However, in the case that an FID is not reached, there could be potential changes in the carrying value in the next financial year due to changes in facts and circumstances that influence the risk factors and thus the overall probability weighting, which drives the recoverable value. This can lead to the recognition of additional impairment of up to $103.2 million. The sensitivity disclosure focuses on the binary nature of these uncertainties leading to FID, this being the most relevant sensitivity disclosure, i.e., failure to achieve any one of the factors will result in failure to achieve FID, which will result in the full impairment of the remaining carrying amount.

A reduction or increase in the two-year forward curve of $5/bbl, based on the approximate range of annualised average oil price over recent history and a reduction or increase in the medium- and long-term price assumptions of $5/bbl, based on the range of annualised average historical prices, are considered to be reasonably possible changes for the purposes of sensitivity analysis. Decreases to oil prices specified above would increase the impairment charge by $18.5 million, whilst increases to oil prices specified above would result in a reduction in the impairment charge of $18.4 million. A 1% change in the pre-tax discount rate would result in an additional impairment charge of $15.4 million. The Group believes a 1% change in the pre-tax discount rate to be a reasonable possibility based on historical analysis of the Group's and a peer group of companies' impairments.

Applying Net Zero emissions by 2050 to the current risking will result in an additional impairment charge of $103.2 million.

9. Property, plant and equipment

$m	2024 Oil and gas assets	2024 Other fixed assets	2024 Right of use assets	2024 Total	2023 Oil and gas assets	2023 Other fixed assets	2023 Right of use assets	2023 Total
Cost								
At 1 January	11,282.1	21.9	1,268.8	12,572.8	11,182.6	30.0	1,196.8	12,409.4
Additions	151.6	3.1	1.4	156.1	416.1	2.3	81.1	499.5
Acquisitions	97.4	–	–	97.4	–	–	–	–
Transfer to assets held for sale	–	–	–	–	(302.8)	–	–	(302.8)
Asset retirement	–	(1.3)	(145.3)	(146.6)	(67.7)	(11.0)	(10.6)	(89.3)
Currency translation adjustments	(17.3)	(0.3)	(0.5)	(18.1)	53.9	0.6	1.5	56.0
At 31 December	11,513.8	23.4	1,124.4	12,661.6	11,282.1	21.9	1,268.8	12,572.8
Depreciation, depletion and amortization and impairment								
At 1 January	(9,377.7)	(17.5)	(644.8)	(10,040.0)	(8,888.4)	(24.4)	(515.2)	(9,428.0)
Charge for the year	(350.3)	(2.5)	(91.4)	(444.2)	(351.6)	(3.6)	(81.4)	(436.6)
Impairment reversal/(Impairment)	11.8	–	–	11.8	(399.1)	–	(9.0)	(408.1)
Capitalised depreciation	–	–	(29.5)	(29.5)	–	–	(49.3)	(49.3)
Transfer to assets held for sale	–	–	–	–	247.6	–	–	247.6
Asset retirement	–	1.3	145.3	146.6	67.7	11.0	10.6	89.3
Currency translation adjustments	17.3	0.1	0.4	17.8	(53.9)	(0.5)	(0.5)	(54.9)
At 31 December	(9,698.9)	(18.6)	(620.0)	(10,337.5)	(9,377.7)	(17.5)	(644.8)	(10,040.0)
Net book value at 31 December	1,814.9	4.8	504.4	2,324.1	1,904.4	4.4	624.0	2,532.8

The Group applied the following nominal oil price assumption for impairment assessments:

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 onwards
2024	$74/bbl	$71/bbl	$75/bbl	$75/bbl	$75/bbl	$75/bbl inflated at 2%
2023	$78/bbl	$75/bbl	$75/bbl	$75/bbl	$75/bbl	$75/bbl inflated at 2%

	Trigger for 2024 Impairment/ (reversal)	2024 Impairment/ (reversal) $m	Pre-tax discount rate assumption	2024 Remaining recoverable amount[e] $m
Espoir (Cote D'Ivoire)	a	2.5	14%	–
Mauritania	b	(19.7)	n/a	–
UK CGU	c,d	5.4	n/a	–
Impairment reversal		(11.8)		

a. Change to decommissioning discount rate.
b. Impairment reversal driven by operational efficiencies and scope revision.
c. Change to decommissioning estimate.
d. The fields in the UK are grouped into one CGU as all fields share critical gas infrastructure.
e. The remaining recoverable amount of the asset is its value in use.

	Trigger for 2023 impairment/ (reversal)	2023 Impairment/ (reversal) $m	Pre-tax discount rate assumption	2023 Remaining recoverable amount[g] $m
Espoir (Cote d'Ivoire)	a,c	53.5	14%	0.4
TEN (Ghana)	b,c	301.2	14%	528.3
Mauritania	d	27.9	n/a	–
UK CGU	d,e	16.5	n/a	–
UK Corporate	f	9.0	n/a	–
Impairment		408.1		

a. Increase in production and development costs.
b. Revision of value based on revisions to reserves.
c. Revision of short, medium and long-term oil price assumptions.
d. Change to decommissioning estimate.
e. The fields in the UK are grouped into one CGU as all fields share critical gas infrastructure.
f. Fully impaired right-of-use asset relating to a vacant office space.
g. The remaining recoverable amount of the asset is its value in use.

10. Other assets

$m	2024	2023
Non-current		
Amounts due from joint venture partners	333.1	332.5
VAT recoverable	7.7	6.1
	340.8	338.6
Current		
Amounts due from joint venture partners	350.2	498.1
Underlifts	20.9	47.8
Prepayments	17.1	21.1
Other current assets	3.7	4.2
	391.9	571.2
	732.7	909.8

Non-current receivables from JV Partners include the Ghana decommissioning fund, which relates to the requirement for JV Partners of the Unitisation and Unit Operating Agreement (UUOA) to establish a trust fund in which the estimated cost of decommissioning and abandonment are accrued to cover decommissioning obligations in respect of the Jubilee Field Unit when the trigger date occurs. As at 31 December 2024, Tullow has contributed $11.6 million (2023: $nil) into the decommissioning trust fund.

The decrease in current receivables from JV Partners compared to December 2023 mainly relates to partner's share of decreased accrual balances (note 12), net decrease in GNPC (Ghana National Petroleum Corporation) receivables, lower balance of current receivables relating to leases (note 13), and other working capital movements.

11. Business combination

On 29 February 2024, the Group completed the asset swap agreement (ASA) transaction with Perenco Oil and Gas Gabon S.A (Perenco). The rationale for the Transaction is the simplification of the Group's equity ownership across key fields in Gabon, creating better alignment between the participating interest partners and streamlining processes such as budgeting, cost management and capital allocation. The revised portfolio of assets will enable Tullow to leverage its technical skills and focus on more material positions in key fields.

The transaction is an asset swap achieved through the exchange of participating interests held by both parties in certain licences in Gabon. The exchange represents the acquisition of an additional interest in a joint operation that constitutes a business, and therefore IFRS 11 Joint Arrangements requires the application of the principles in IFRS 3 Business Combinations.

In line with the requirements of IFRS 3, the interests transferred as part of the consideration, which comprises mainly of property, plant, and equipment of $54.4 million, have been remeasured to the acquisition date fair value of $93.3 million. This has resulted in an asset revaluation gain of $38.9 million recognised in the income statement at 31 December 2024.

The below table shows the pre-completion and post-completion equities in the licences subject to the transaction:

Field		Pre-completion	Post-completion
Kowe (Tchatamba)	Acquisition	25.0%	40.0%
DE8	Acquisition	20.0%	40.0%
Simba	Disposal	57.5%	40.0%
Limande	Disposal	40.0%	0%
Turnix	Disposal	27.5%	0%
Moba	Disposal	24.3%	0%
Oba	Disposal	10.0%	0%

The exchange of the transferred interests between the parties was deemed for all purposes to be made with effect from the economic date of 1 February 2023, but completed on 29 February 2024 and this is therefore the acquisition date. The transaction was intended to be cash neutral on the economic date as the fair value of the assets exchanged were considered to be equal at that time, and therefore no additional consideration would have been payable by either party at that time. However, as the transaction completed more than a year later, the ASA included provisions to ensure the neutrality of the transaction via cash adjustments for the period between the economic date and the completion date, the agreed adjustment upon completion was $8.1 million, which has been included in investing activities in the cash flow statement.

11. Business combination continued

The fair values of the identifiable assets and liabilities acquired were:

	Fair value recognised on acquisition $m
Intangible assets	1.0
Property, plant and equipment	97.4
Other current assets	0.7
Goodwill	44.9
Total assets acquired	144.0
Provisions	(5.8)
Deferred tax liabilities	(44.9)
Total liabilities assumed	(50.7)
Net identifiable assets acquired	93.3
Total purchase consideration	(93.3)
Consideration satisfied by exchange of assets	(85.2)
Consideration satisfied by cash	(8.1)
Purchase of additional interest in joint operation per the cash flow statement	(8.1)

The disclosure requirement of IFRS 3 in relation to contributions to revenue and profit or loss have not been included as they are impracticable to obtain due to Tullow not being the operator of the assets.

No material acquisition-related costs were incurred in relation to the transaction.

Valuation methodology and assumptions

The fair value of the purchase consideration of $93.3 million reflects the discounted future cash flows of the assets and liabilities exchanged as part of the swap as the transaction is intended to be value neutral. Provisions represent the present value of decommissioning costs which are expected to be incurred after the end of the licence in 2046.

Goodwill

Goodwill of $44.9 million was recognised from the asset swap. IAS 12 Income Taxes requires recognition of a deferred tax asset or liability for the difference between the fair value of the assets acquired and liabilities assumed, and their respective tax bases. Therefore, goodwill has arisen as a direct result of the recognition of the deferred tax liability. None of the goodwill is deductible for income tax purposes.

The goodwill acquired through the business combination is allocated fully to the Tchatamba cash-generating unit (CGU), for the purposes of impairment testing. Refer to Note 9 for full disclosure of the outcome of the impairment test at 31 December 2024. Significant headroom remained between the net present value (NPV) and the book value of the CGU and management did not identify an impairment for this CGU.

Asset held for sale

As at 31 December 2024, the Group had no assets classified as held for sale (2023: $55.8 million) and no liabilities associated with assets classified as held for sale (2023: $17.6 million). The previously classified AHFS, relating to the Gabon asset swap, was derecognised when the transaction was completed during the year as disclosed above.

12. Trade and other payables

$m	2024	2023
Current		
Trade payables	75.7	22.3
Other payables	96.8	65.3
Overlifts	38.3	3.1
Accruals	373.8	498.6
Current portion of leases	151.9	185.7
	736.5	775.0
Non-current		
Other non-current liabilities[1]	84.9	62.2
Non-current portion of leases	581.0	721.0
	665.9	783.2

1. Other non-current liabilities include balances related to JV Partners.

Accruals relate to operating and administrative expenditure of $196.3 million (2023: $209.2 million), capital expenditure of $119.6 million (2023: $225.6 million), interest expense on bonds of $35.3 million (2023: $40.9 million) and staff-related expenses of $22.6 million (2023: $22.9 million). The movement in the balance is predominantly driven by a decreased work programme in Ghana during 2024 compared to 2023.

Trade and other payables are non-interest bearing except for leases (Note 13). The change in trade payables and in other payables represents timing differences and levels of work activity.

Payables related to operated Joint Ventures (primarily in Ghana) are recorded gross with the amount representing the partners' share recognised in amounts due from Joint Venture Partners (Note 10).

The movement in current and non-current lease liabilities is mainly driven by the level of drilling activity in Ghana (Note 13).

13. Leases

This note provides information for leases where the Group is a lessee. The Group did not enter into any contracts acting as a lessor.

i) Amounts recognised in the balance sheet

	Right-of-use assets		Lease liabilities	
$m	2024	2023	2024	2023
Right-of-use assets (included within property, plant and equipment) and lease liabilities				
Property leases	18.2	22.0	26.1	27.6
Oil and gas production and support equipment leases	466.4	576.9	661.9	826.4
Transportation equipment leases	19.8	25.1	44.9	52.7
Total	504.4	624.0	732.9	906.7
Current provisions			151.9	185.7
Non-current			581.0	721.0
Total			732.9	906.7

Additions and disposals of right-of-use assets during the 2024 financial year were $1.4 million and $145.3 million, respectively. Refer to Note 9.

TEN FPSO

The Group's leases balance includes the TEN FPSO, classified as oil and gas production and support equipment. During 2023, the assumption that the TEN FPSO lease term would end in April 2024, when the purchase option was assumed to be exercised, was updated to reflect the best estimate view that the FPSO will continue to be leased until the cessation of production in 2032. It also assumes an exercise of the extension option.

The resulting lease liability remeasurement had the following impact on the balances:

$m	2023
Lease liability	(39.2)
Right-of-use asset (included in property, plant and equipment)	25.6
Amounts due from Joint Venture Partners	13.6

13. Leases continued

As at 31 December 2024, the present value of the TEN FPSO right-of-use asset was $466.3 million (2023: $549.0 million).

The present value of the TEN FPSO gross lease liability was $650.0 million (2023: $763.5 million).

A receivable from the Joint Venture Partners of $244.9 million (2023: $288.8 million) was recognised in other assets (Note 10) to reflect the value of future payments that will be met by cash calls from partners relating to the TEN FPSO lease.

The present value of the receivable from the Joint Venture Partners unwinds over the expected life of the lease and the unwinding of the discount is reported in the finance income.

Carrying amounts of the lease liabilities and Joint Venture leases receivables and the movements during the period:

$m	Lease liabilities	Joint Venture lease receivables	Total
At 1 January 2023	(984.1)	376.1	(608.0)
Additions and changes in lease estimates	(174.1)	79.8	(94.3)
Payments/(receipts)	331.5	(136.5)	195.0
Interest (expense)/income	(78.6)	30.1	(48.5)
Currency translation adjustments	(1.4)	–	(1.4)
At 1 January 2024	(906.7)	349.5	(557.2)
Additions and changes in lease estimates	1.6	1.2	2.8
Payments/(receipts)	291.6	(122.6)	169.0
Interest (expense)/income	(119.7)	48.1	(71.6)
Currency translation adjustments	0.3	–	0.3
At 31 December 2024	(732.9)	276.2	(456.7)

ii) Amounts recognised in the statement of profit or loss

$m	2024	2023
Depreciation charge of right-of-use assets		
Property leases	8.5	7.3
Oil and gas production and support equipment leases	82.9	74.1
Total	91.4	81.4
Interest expense on lease liabilities (included in finance costs)	119.7	78.6
Interest income on amounts due from Joint Venture Partners	(48.1)	(30.1)
Expense relating to short-term leases	0.8	1.0
Expense relating to leases of low-value assets	0.6	0.9
Total	164.4	131.8

The total net cash outflow for leases in 2024 was $169.0 million (2023: $195.0 million).

14. Provisions

$m	Decommissioning 2024	Other provisions 2024	Total 2024	Decommissioning 2023	Other provisions 2023	Total 2023
At 1 January	377.9	93.7	471.6	398.1	116.3	514.4
New provisions	–	22.4	22.4	–	(10.4)	10.4
Changes in estimate	(39.3)	(75.9)	(115.2)	47.8	(32.3)	15.5
Acquisitions[1]	5.8	–	5.8	–	–	–
Transfer to assets and liabilities held for sale	–	–	–	(14.2)	–	(14.2)
Payments	(49.0)	(0.7)	(49.7)	(66.4)	(0.6)	(67.0)
Unwinding of discount	11.4	–	11.4	10.1	–	10.1
Currency translation adjustment	(0.4)	(0.1)	(0.5)	2.5	(0.1)	2.4
At 31 December	306.4	39.4	345.8	377.9	93.7	471.6
Current provisions[2]	9.8	14.5	24.3	53.4	14.5	67.9
Non-current provisions[2]	296.6	24.9	321.5	324.5	79.2	403.7

1. This relates to an acquisition through business combination discussed in Note 11.
2. In 2024, provisions of $10.0 million were reclassified from current provisions to non-current provisions as management expectations are that the provision will not crystallise within the next 12 months.

Other provisions include non-income tax provisions of $7.1 million (2023: $38.8 million) and $32.3 million (2023: $54.9 million) of disputed cases and claims. Management estimates non-current other provisions would fall due between two and five years.

New other provisions include $7.1 million for the restructuring programme that commenced in December 2024. Changes in estimate of other provisions includes a reduction of $31.1 million in relation to the BPRT arbitration ruling.

Non-current other provisions include a provision relating to a potential claim arising out of historical contractual agreement. Further information is not provided as it will be seriously prejudicial to the Group's interest.

The decommissioning provision represents the present value of decommissioning costs relating to the UK and African oil and gas interests. The Group has assumed cessation of production as the estimated timing for outflow of expenditure. However, expenditure could be incurred prior to cessation of production or after and actual timing will depend on a number of factors, including underlying cost environment, availability of equipment and services and allocation of capital.

Decommissioning provisions	Inflation assumption[1]	Discount rate assumption 2024	Cessation of production assumption 2024	Total 2024 $m	Discount rate assumption 2023	Cessation of production assumption 2023	Total 2023 $m
Côte d'Ivoire	2.0%	4.5%	2027	50.0	3.5%	2032	47.1
Gabon	2.0%	4.5-5.0%	2030-2047	30.7	3.5-4.0%	2034-2047	28.7
Ghana	2.0%	4.5%	2033-2036	195.6	3.5%	2032-2036	208.2
Mauritania	n/a	n/a	2018	1.1	n/a	2018	54.7
UK	n/a	n/a	2018	29.0	n/a	2018	39.2
				306.4			377.9

1. Short-term inflation rate assumption has increased from 2.0% to 2.5% in 2025. Long-term rates of 2% remained unchanged from 31 December 2023.

The Group's decommissioning activities are ongoing in the UK and Mauritania, with $10.0 million of the future costs expected to be incurred in 2025. The remaining activities are planned to continue through to 2027, with an associated expenditure of $20.0 million, mostly in the UK.

15. Commercial reserves and contingent resources summary working interest basis

	Ghana		Non-Operated[7]		Kenya		Total		
	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Petroleum mmboe[6]
COMMERCIAL RESERVES[1]									
1 January 2024	143.8	151.7	41.9	6.8	-	-	185.7	158.5	212.2
Revisions[3,4]	(22.9)	-	(1.6)	(4.5)	-	-	(24.5)	(4.5)	(25.3)
Production	(16.1)	(13.3)	(3.9)	(1.2)	-	-	(20.0)	(14.5)	(22.4)
Acquisitions[5]	-	-	-	-	-	-	-	-	-
Disposals[5]	-	-	-	-	-	-	-	-	-
31 December 2024	104.8	138.4	36.4	1.1	-	-	141.2	139.5	164.5
CONTINGENT RESOURCES[2]									
1 January 2024	152.8	511.0	35.1	9.7	470.4	-	658.3	520.7	745.0
Revisions[3,4]	(26.4)	(72.2)	10.9	4.2	(7.2)	-	(22.7)	(68.0)	(34.0)
Acquisitions[5]	-	-	-	-	-	-	-	-	-
Disposals[5]	-	-	-	-	-	-	-	-	-
31 December 2024	126.4	438.8	46.0	13.9	463.2	-	635.6	452.7	711.0
TOTAL									
31 December 2024	231.2	577.2	82.4	15.0	463.2	-	776.8	592.2	875.5

1. Reserves presented are ‘proven and probable’. They are as audited and reported by the independent third-party reserves auditor as at year end 2024.
2. Contingent resources are ’best estimate‘. They are as audited and reported by the independent third-party reserves auditor as at year end 2024.
3. Reserves and resources revisions in Ghana are primarily related to production performance during 2024 on Jubilee and include an upwards revision of TEN reserves, supported by substantial progress towards a material reduction in fixed costs, including in relation to the FPSO, which extends the economic life to 2036.
4. Reserves revisions in the non-operated portfolio primarily reflect an earlier assumed cessation of production on the Espoir field.
5. There have been no acquisitions or disposals in 2024. The asset swap in Gabon, in which M’Oba, Oba, Limande, Turnix and a percentage of Simba were exchanged for an increased working interest in Tchatamba and the DE8 licence, was already accounted for in the 1 January 2024 reserve and resource position.
6. A gas conversion factor of 6 mscf/boe is used to calculate the total petroleum mmboe.
7. Non-Operated consists of assets located in Gabon and Cote d’Ivoire.

The Group provides for depletion and amortisation of tangible fixed assets on a net entitlements basis, which reflects the terms of the Production Sharing Contracts related to each field. Total working interest reserves were 161.5 mmboe at 31 December 2024 (31 December 2023: 204.5 mmboe).

Contingent resources are discovered resources for which development plans are either in the course of preparation, on hold or further evaluation is under way with a view to future development.

Alternative performance measures

The Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures include capital investment, net debt, gearing, adjusted EBITDAX, underlying cash operating costs, free cash flow, underlying operating cash flow and pre-financing cash flow.

Capital investment

Capital investment is defined as additions to property, plant and equipment and intangible exploration and evaluation assets less decommissioning asset additions, right-of-use asset additions, capitalised share-based payment charge, capitalised finance costs, additions to administrative assets, and certain other adjustments. The Directors believe that capital investment is a useful indicator of the Group's organic expenditure on exploration and evaluation assets and oil and gas assets incurred during a period because it eliminates certain accounting adjustments such as capitalised finance costs and decommissioning asset additions.

$m	2024	2023
Additions to property, plant and equipment	249.0	416.1
Additions to intangible exploration and evaluation assets	34.7	25.4
Less		
Changes to decommissioning asset estimates	(39.3)	47.8
Right-of-use asset additions	1.4	81.1
Lease payments related to capital activities	(21.9)	(53.6)
Additions to administrative assets	3.1	2.3
Other non-cash capital movements[1]	109.3	(16.0)
Capital investment	**231.1**	**379.9**
Movement in working capital	(1.6)	(89.7)
Additions to administrative assets	3.1	2.3
Cash capital expenditure per the cash flow statement	**232.6**	**292.5**

1. Other Non-cash capital movements includes $95 million of additions in relation to asset swap with Perenco in Gabon.

Net debt

Net debt is a useful indicator of the Group's indebtedness, financial flexibility and capital structure because it indicates the level of cash borrowings after taking account of cash and cash equivalents in the Group's business that could be utilised to pay down the outstanding cash borrowings. Net debt is defined as current and non-current borrowings plus non-cash adjustments, less cash and cash equivalents. Non-cash adjustments include unamortised arrangement fees, adjustment to convertible bonds, and other adjustments. The Group's definition of net debt does not include the Group's leases as the Group's focus is the management of cash borrowings and a lease is viewed as deferred capital investment. The value of the Group's lease liabilities as at 31 December 2024 was $151.9 million current and $581.0 million non-current; it should be noted that these balances are recorded gross for operated assets and are therefore not representative of the Group's net exposure under these contracts.

$m	2024	2023
Current borrowings	589.4	100.0
Non-current borrowings	1,386.4	1,984.6
Non-cash adjustments[1]	31.6	22.8
Less cash and cash equivalents[2]	(555.1)	(499.0)
Net debt	**1,452.3**	**1,608.4**

1. Non-cash adjustments include unamortised arrangement fees which are incurred on creation or amendment of borrowing facilities.

2. Cash and cash equivalents include an amount of $83.5 million (2023: $36.9 million) which the Group holds as operator in joint venture bank accounts. Included within cash at bank is $6.5 million (2023: $4.5 million) of restricted cash held as collateral for performance bonds issued in relation to exploration activity.

Gearing and Adjusted EBITDAX

Gearing is a useful indicator of the Group's indebtedness, financial flexibility and capital structure and can assist securities analysts, investors and other parties to evaluate the Group. Gearing is defined as net debt divided by adjusted EBITDAX. Adjusted EBITDAX is defined as profit/(loss) from continuing activities adjusted for income tax expense, finance costs, finance revenue, loss on hedging instruments, asset revaluation, other gains, depreciation, depletion and amortisation, share-based payment charge, provision reversal, gain on bond buyback, exploration costs written off, impairment (reversal)/impairment of property, plant and equipment net, expected credit loss charge on trade receivables and restructuring provision.

$m	2024	2023
Profit/(Loss) from continuing activities	54.6	(109.6)
Adjusted for		
Income tax expense	266.9	205.5
Finance costs	345.6	329.6
Finance revenue	(71.5)	(44.0)
Loss on hedging instruments	-	0.4
Asset revaluation	(38.9)	-
Other gains	-	(0.2)
Depreciation, depletion and amortisation	444.2	436.6
Share-based payment charge	6.9	6.0
Provision reversal	(70.4)	(22.0)
Gain on bond buyback	-	(86.0)
Exploration costs written off	212.6	27.0
Impairment (reversal)/Impairment of property, plant and equipment, net	(11.8)	408.1
Expected credit loss charge on trade receivables	6.6	-
Restructuring provision	7.1	-
Adjusted EBITDAX	1,151.9	1,151.4
Net debt	1,452.3	1,608.4
Gearing (times)	1.3	1.4

Underlying cash operating costs

Underlying cash operating costs is a useful indicator of the Group's costs incurred to produce oil and gas. Underlying cash operating costs eliminates certain non-cash accounting adjustments to the Group's cost of sales to produce oil and gas. Underlying cash operating costs is defined as cost of sales less operating lease expense, depletion and amortisation of oil and gas assets, underlift, overlift and oil stock movements, share-based payment charge included in cost of sales, royalties and certain other cost of sales. Underlying cash operating costs are divided by production to determine underlying cash operating costs per boe.

In 2023 and 2024, Tullow incurred abnormal non-recurring costs, which are presented separately below. The adjusted normalised cash operating costs are a helpful indicator to the forward underlying costs of the business.

$m	2024	2023
Cost of sales	780.9	869.2
Add		
Lease payments related to operating activity	11.6	7.2
Less		
Depletion and amortisation of oil and gas and leased assets[1]	437.6	430.8
Underlift, overlift and oil stock movements[2]	42.5	109.3
Share-based payment charge included in cost of sales	0.4	0.4
Royalties	27.9	33.9
Other cost of sales[3]	11.7	9.1
Underlying cash operating costs	272.4	292.9
Non-recurring costs[4]	(8.3)	(25.9)
Total normalised cash operating costs	264.1	267.0
Production (MMboe)	22.4	22.9
Underlying cash operating costs per boe ($/boe)	12.2	12.8
Normalised cash operating costs per boe ($/boe)	11.8	11.7

1.Depletion and amortisation of oil and gas assets is the depreciation and amortisation of the Group's oil and gas assets over the life of an asset on a unit of production basis.

2.Under lifting or offtake arrangements for oil and gas produced in certain operations in which the Group has interests with other commercial partners, each participant may not receive and sell its precise share of the overall production in each period. The resulting imbalance between cumulative entitlement and cumulative production less stock constitutes "underlift" or "overlift". Underlift and overlift are valued at market value and included within other current assets and other current payables on the Group's balance sheet, respectively. Movements during an accounting period are charged to cost of sales rather than charged through revenue, and as a result gross profit is recognised on an entitlements basis.

3.Other cost of sales includes purchases of gas from third parties to fulfil gas sales contracts and royalties paid in cash.

4.Non-recurring costs include vessel Class maintenance related works and shutdown preparation costs.

Free cash flow

Free cash flow is a useful indicator of the Group's ability to generate cash flow to fund the business and strategic acquisitions, reduce borrowings and provide returns to shareholders through dividends. Free cash flow is defined as net cash from operating activities, and net cash used in investing activities, repayment of obligations under leases, finance costs paid and foreign exchange gain/(loss).

$m	2024	2023
Net cash from operating activities	758.5	876.2
Net cash used in investing activities	(213.1)	(268.5)
Repayment of obligations under leases	(169.0)	(195.0)
Finance costs paid	(223.2)	(240.0)
Foreign exchange gain/(loss)	2.9	(2.5)
Free cash flow	156.1	170.2

Underlying operating cash flow

This is a useful indicator of the Group's assets' ability to generate cash flow to fund further investment in the business, reduce borrowings and provide returns to shareholders. Underlying operating cash flow is defined as net cash from operating activities less repayment of obligations under leases plus decommissioning expenditure.

Pre-financing cash flow

This is a useful indicator of the Group's ability to generate cash flow to reduce borrowings and provide returns to shareholders through dividends. Pre-financing free cash flow is defined as net cash from operating activities, and net cash used in investing activities, less repayment of obligations under leases and foreign exchange gain.

$m	2024	2023
Net cash from operating activities	758.5	876.2
Add		
Decommissioning expenditure	45.0	78.1
Lease payments related to capital activities	21.9	53.6
Payments to decommissioning escrow fund	11.6	-
Less		
Repayment of obligations under leases	(169.0)	(195.0)
Underlying operating cash flow	668.0	812.9
Net cash used in investing activities	(213.1)	(268.5)
Decommissioning expenditure	(45.0)	(78.1)
Lease payments related to capital activities	(21.9)	(53.6)
Payments to decommissioning escrow fund	(11.6)	-
Pre-financing cash flow	376.4	412.7

MANAGEMENT PRESENTATION - WEBCAST – 09:00

To access the webcast please use the following link and follow the instructions provided:

https://meetings.lumiconnect.com/100-695-362-491

A replay will be available on the website from midday on 25 March 2025:

https://www.tullowoil.com/investors/results-reports-and-presentations/

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Notes to editors

Tullow is an independent energy company that is building a better future through responsible oil and gas development in Africa. The Company's operations are focused on its West-African producing assets in Ghana, Gabon and Côte d'Ivoire, alongside a material discovered resource base in Kenya. Tullow is committed to becoming Net Zero on its Scope 1 and 2 emissions by 2030 and has a Shared Prosperity strategy that delivers lasting socio-economic benefits for its host nations. The Group is quoted on the London and Ghana stock exchanges (symbol: TLW). For further information, please refer to: www.tullowoil.com.

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