TULLOW

2023

Full Year Results

Tullow Oil plc

6 March 2024

TULLOW OIL PLC - 2023 FULL YEAR RESULTS

Successful delivery of business plan

2023 free cash flow ahead of expectations and net debt reduction accelerated

Production growth expected in 2024

6 March 2024 – 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 2023.

Rahul Dhir, Chief Executive Officer, Tullow Oil plc, commented today:

"2023 was a year of significant achievements, including start-up of Jubilee South East that delivered material production growth from our core operated field, a new revenue stream established from the sale of Ghana associated gas; and reserves growth in Gabon through licence extensions. We also generated free cash flow ahead of expectations despite a lower year-on-year realised oil price and demonstrated our ability to access long-term capital through the $400 million debt facility agreement with Glencore.

"In line with our strategy, we are continuing to focus relentlessly on operational excellence, capital efficiency and investments to drive growth. This strategy is delivering material cashflow generation and we are on track to deliver our target of c.$800 million free cash flow over the 2023 to 2025 period and optimise our capital structure.

"Tullow has a strong and unique foundation to create material value for our investors, host nations and stakeholders and we look to the future with confidence."

2023 FULL YEAR RESULTS OVERVIEW

- Group working interest oil and gas production 62.7 kboepd; (2022: 61.1 kboepd).
- Revenue of $1,634 million (2022: $1,783 million), a year-on-year reduction driven by c.12% lower realised post-hedge oil price of $77.5/bbl (2022: $88.0/bbl).
- Adjusted EBITDAX[1] of $1,151 million (2022: $1,469 million); gross profit of $765 million (2022: $1,086 million); loss after tax of $110 million (2022: profit after tax of $49 million) driven by impairments and write-offs totalling $435 million (2022: $391 million).
- Free cash flow[1] of $170 million (2022: $267 million) ahead of guidance despite increased capital expenditure of $380 million (2022: $354 million) and decommissioning spend of $67 million (2022: $72 million).
- Net debt[1] at year-end reduced to $1,608 million (2022: $1,864 million); cash gearing of net debt to adjusted EBITDAX[1] of 1.4 times (2022: 1.3 times); liquidity headroom of $1,000 million (2022: $1,055 million).
- Material step in refinancing strategy with new $400 million five-year Glencore debt facility, with proceeds available for liability management of the senior notes maturing in March 2025.
- Completed major infrastructure project with Jubilee South East brought onstream, marking a material step up in production at Jubilee which surpassed 100,000 bopd gross.
- Strong operating, drilling and completion performance, with seven Jubilee wells brought onstream and facilities uptime of c.96% in Ghana.
- c.$30 million revenue from commercialisation of Jubilee associated gas through Interim Gas Sales Agreement.
- Increased Gabon reserves and centred portfolio around Tchatamba production hub through swap agreement and licence extensions.
- Sale and exit of Guyana business, in line with strategy to focus portfolio on high-return assets in Africa.

2024 GUIDANCE

- Production growth in 2024 with group working interest production expected to average between 62 to 68 kboepd, including c.7 kboepd of gas.
- 2024 capital expenditure of c.$250 million, comprising c.$160 million in Ghana, c.$60 milllion on the non-operated portfolio, c.$10 million in Kenya and c.$20 on exploration. Decommissioning spend of c.$50 million for UK and Mauritania; c.$20 million provisioning for Ghana and Gabon.
- Cash taxes expected to be c.$350 million at $80/bbl, with payments weighted to the first half of the year.
- Forecast free cash flow of $200-300 million at $80/bbl, with the range largely driven by timing of revenue receipts for 18 to 19 cargoes lifted in Ghana during the year.
- Year-end net debt expected to be less than $1.4 billion; cash gearing of net debt to EBITDAX expected to be c.1x at $80/bbl.
- On track to deliver targeted c.$800 million free cash flow over 2023 to 2025 period, with over $600 million free cash flow expected to be generated over 2024 to 2025 at $80/bbl.

[1].Alternative performance measures are reconciled on pages 32 to 35.

MANAGEMENT PRESENTATION - WEBCAST – 9:00 GMT

To access the webcast please use the following link and follow the instructions provided:
https://web.lumiconnect.com/#/m/118077766

A replay will be available on the website from midday on 6 March 2024:

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

CONTACTS

Tullow Oil plc	Camarco
(London) (+44 20 3249 9000) Nicola Rogers Matthew Evans	**(London)** (+44 20 3781 9244) Billy Clegg Andrew Turner Rebecca Waterworth

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

Successful delivery of business plan

Soon after I joined Tullow in July 2020, we put in place a plan to transform our business. This plan is achieving targeted results and since the end of 2020 we have generated over $1.1 billion of free cash flow, reduced net debt by over 30% and taken the business from peak gearing of 3x to 1.4x net debt to EBITDAX. We have achieved this despite our legacy hedge programme resulting in non-recurring outflows of c.$600 million between 2021 to 2023, which suppressed the true cash flow generation capacity of our business.

In 2023, Tullow continued to evolve and we now have a strong and unique foundation to create material value. Several significant milestones have been achieved, including the start-up of Jubilee South East which delivered material production growth from our core operated field. We generated $170 million of free cash flow, ahead of expectations, and reduced our net debt by over $250 million, despite a lower realised oil price in 2023 compared to 2022 that drove a year-on-year reduction in revenue (2023: $1,634 million; 2022: $1,783 million). We also demonstrated our ability to access capital through the $400 million debt facility agreement with Glencore.

Our strategy is underpinned by a relentless focus on three core areas – operational excellence, capital efficiency and business growth. Through continued execution of this strategy, we are embedding a performance culture, retaining our discipline, and establishing a growth outlook. Importantly, we are now a highly cash generative business and on track to deliver our target of c.$800 million free cash flow over the 2023 to 2025 period.

Sustainability and shared prosperity

Tullow is committed to building a better future through responsible oil and gas development. We believe Africa has the potential to play a growing role in the global energy mix and we actively partner with our host nations to develop their resources in a low-cost, environmentally and socially responsible manner. We are encouraged by the commitment to a "just and equitable" energy transition articulated in the COP28 Agreement. This acknowledges Africa's minimal contribution to global emissions and recognises the right of African developing nations to benefit from the development of their natural resources.

Our Shared Prosperity strategy creates economic opportunities for those who need it most. In 2023, we accelerated our impact through partnerships, supporting more than 10,000 students and hundreds of businesses across our countries of operation. We are also driving local content through increased engagement, support and training of our local supplier base

We have made tangible progress on our pathway to Net Zero by 2030. In 2023, several process improvement modifications were completed at the Jubilee and TEN FPSOs, keeping us on track to reach our target to eliminate routine flaring by 2025. To address the hard-to-abate residual emissions from our assets, we are taking a hands-on approach to progress a nature-based solution in partnership with the Ghana Forestry Commission and expect to make a Final Investment Decision in 2024. The project delivers on our 2030 Net Zero ambition while also advancing Ghana's national climate goals and aligning with our Shared Prosperity agenda.

Governance

At the beginning of the year Richard Miller was confirmed as Chief Financial Officer (CFO), having served as interim CFO since April 2022, and joined the Board as an Executive Director. Roald Goethe and Rebecca Wiles were appointed to the Board as independent non-executive Directors in February and June 2023, respectively. Roald is a highly experienced oil and gas executive who spent a major part of his career at Trafigura where he worked primarily in West Africa. Rebecca brings deep technical subsurface and geoscience expertise to Tullow, following a 33-year career at BP plc. Our Board members bring a diverse experience set including a deep understanding of Africa, the oil & gas industry, finance and plc governance. Three out of nine directors are women.

Operational performance

In 2023, full year working interest production averaged 62.7 kboepd, including 6.9 kboepd of gas. Group working interest production is expected to increase year-on-year and our guidance range for 2024 is 62-68 kboepd, including c.7 kboepd of gas production.

Group working interest production (kboepd)	FY 2023	FY 2024 Guidance
Ghana oil	42.6	48
Jubilee oil	*32.5*	*39*
TEN oil	*10.1*	*9*
Non-operated portfolio oil	13.2	11
Gabon oil	*12.2*	*10*
Cote d'Ivoire oil	*1.0*	*1*
Gas production	6.9	7
Group	**62.7**	**62-68**

Ghana

The start-up of production from the Jubilee South East project in July was a landmark event, marking a step change in the field's production with average daily rates c.30% higher in the second half of the year compared to the first half with rates reaching levels over 100 kbopd.

Gross oil production from the Jubilee field averaged 83.4 kbopd (32.5 kbopd net) in 2023. This was below our expectations, primarily due to water injection reliability challenges and Jubilee South East starting up slightly later than planned. The water injection reliability issues were resolved in the fourth quarter of 2023, with upgraded capacity delivering record water injection rates and observable pressure response in the reservoirs, which will benefit 2024 production and beyond. Jubilee gas processing was also upgraded in 2023 and as a result, we have increased capacity to produce oil from wells with higher associated gas content. These important facility upgrades put us in a strong position to maintain production in the range of 90-110 kbopd towards the end of the decade.

Gross oil production from the TEN fields averaged 18.4 kbopd (net: 10.1 kbopd) during 2023, with improved pressure support from existing injection wells resulting inbetter management of decline. A planned shutdown was carried out in July and work was completed to improve asset integrity, enhance production through improved liquid recovery from gas and reduce flaring. Flaring from TEN reduced by over 50% post the shutdown, an important step forward in our target to eliminate routine flaring by 2025.

During the year, our operational performance continued to strengthen and average uptime across our Ghana FPSOs remained high at 96%. The drilling team also had excellent performance with seven wells (four Jubilee producers and three Jubilee water injectors) brought onstream during 2023. The cost of drilling wells in 2023 was on average around 20% lower and c.38 days faster than the previous campaign in 2018-2020, achieving top-quartile industry performance. These cost savings and efficiencies have been driven by reducing non-productive time, improved well design and more effective contracting.

Five new Jubilee wells (three producers and two water injectors) are scheduled to come onstream in 2024. The first water injector was brought on stream in January, and two producers were brought on stream in February, with gross production currently averaging over 100 kbopd. We expect to complete the current drilling programme around the middle of the year, approximately six months ahead of schedule. We then intend to take a drilling break in Ghana with plans to resume drilling in 2025. During this time, we will optimise our plans for the next phase of investment in Ghana while the existing well stock and upgraded water injection capacity sustains production at Jubilee and TEN decline continues to be effectively minimised through improved pressure support.

Net gas production in Ghana averaged 6.4 kboepd in 2023 and marked the first commercialisation of associated gas from the Jubilee field. The interim Gas Sales Agreement, initially valued at $0.50/mmbtu, was amended in July 2023 to a price of $2.90/mmbtu and subsequently increased in November to $2.95/mmbtu, after applying year-on-year inflation indexation. This agreement represents a revenue stream for Tullow of c.$4 million per month.

During the year, discussions continued with the Government of Ghana on the amended TEN Plan of Development (PoD) and the long-term gas sales agreement. We remain committed to reaching agreement and progressing a number of identified projects at TEN in addition to commercialising the material gas resource base.

In February 2023, we announced that Tullow Ghana Limited (TGL) had filed requests for arbitration with the International Chamber of Commerce in London in respect of two disputed tax assessments received from the Ghana Revenue Authority (GRA). The assessments relate to the disallowance of loan interest deductions for the fiscal years 2010 – 2020 and proceeds received by Tullow Oil plc during the financial years 2016 to 2019 under the Group's corporate Business Interruption Insurance policy.

Tullow had also previously filed a request for arbitration in respect of a separate assessment for Branch Profits Remittance Tax of $320 million in 2021. A hearing in respect of this dispute took place in October 2023 with an outcome expected this year.

We believe that resolution through international arbitration will bring certainty, which is in the best interest of all stakeholders. In the meantime, we continue to engage with the Government of Ghana, including the GRA, with the aim of resolving these disputes on a mutually acceptable basis.

Non-operated and exploration portfolios

In line with expectations, production from our non-operated portfolio in Gabon and Côte d'Ivoire averaged 13.7 kboepd net in 2023 (2022: 16.7 kboepd net), including 0.5 kboepd of gas production in Côte d'Ivoire.

Gabon is a key part of our production and infrastructure-led exploration (ILX) portfolio and in 2023 we took actions that place the Tchatamba facilities as a core hub for Tullow. In April, we announced the cashless asset swap agreed with Perenco that enabled us to take more material positions in key fields around Tchatamba. In August, the Government of Gabon approved the extension of several of our licences to 2046, reflecting the future potential of the fields and the longevity of the Tchatamba facilities. 2P reserves additions from the licence extensions and the asset swap amounts to c.6 mmbbls with a further c.3 mmbbls 2P positive reserves revision from asset performance, overall representing c.190% reserves replacement in 2023. During 2024, operations in Gabon will focus on infill drilling to sustain production or minimise decline across the licences, as well as two ILX wells at the Simba licence.

On Espoir in Côte d'Ivoire, we continue to work with the operator to establish the best way forward for the asset. On exploration licences CI-524 and CI-803, we are maturing the prospect inventory ahead of drill candidate selection for an exploration well to potentially be drilled in 2025.

In line with our strategy to focus on producing assets, we no longer have licences in Guyana following the sale of Tullow Guyana B.V. to Eco Atlantic and the expiry of the Kanuku licence. Through the sale, which completed in November 2023, we retain exposure to potential future success on the Orinduik licence through contingent considerations and royalty payments.

In Argentina, our exploration team has continued to mature a significant prospective resource base and continues to assess opportunities from these licences.

Kenya

Kenya remains a material option to drive value and growth for Tullow. An updated Field Development Plan (FDP) which intends to develop 470 mmboe of 2C resources to produce up to 120 kbopd, was submitted to the Government in March 2023. We have since worked collaboratively with the Government as they evaluate the FDP. Once their evaluation is concluded, the FDP will be submitted to the Cabinet Secretary for Energy and Petroleum for review before submission to Parliament for final approval. The development has been designed to be robust at lower oil prices and we continue discussions with prospective strategic partners for this project.

In June 2023, our interest in Kenya increased from 50% to 100% as a result of the withdrawal of our Joint Venture Partners for differing reasons. The increased interest provides us with greater strategic flexibility. While we continue to progress the FDP, we are also actively working with the Government of Kenya in developing options to accelerate production and cash flow to unlock value from this well-matured resource base.

Reserves and resources

At the end of 2023, audited 2P reserves were 212 mmboe (2022: 229 mmboe). During the year, 23 mmboe of 2P reserves were produced with a replacement ratio of 26%. Additions were primarily from the extension of production licences in Gabon and the maturation of several infill wells, both in Gabon and the Jubilee area. These additions were partly offset by reductions in TEN 2P reserves, mainly driven by a reduced near-term development programme in light of the ongoing delays to gain Government approval for the TEN amended PoD. Around 30 mmboe of net gas resources remain classified as 2C pending the approval of the TEN amended PoD and Gas Sales Agreement. Commercialisation of these gas resources would place TEN on a much firmer economic footing and support the maturation of several identified projects.

Tullow's asset base continues to have significant value, and as of 31 December 2023, Tullow's audited 2P NPV10 was $3,406 million. This is slightly down from 2022 ($3,895 million), driven largely by TEN revisions and a lower long-term oil price assumption as defined by independent third-party reserves auditor, TRACS.

The Group's audited 2C resources increased to 745 mmboe at the end of 2023 (2022: 605mmboe), reflecting the material scale of opportunity Tullow has to convert resources into reserves to sustain long-term production. As we now hold 100% of our Kenya licences, net contingent resources have doubled to 470mmboe. 54mmboe of contingent resources has also been removed following the sale and exit from Guyana.

Outlook

After reaching an important inflection point in our business plan in 2023, Tullow has a strong and unique foundation to create material value for our investors, host nations and wider stakeholders and we look to the future with confidence.

We will continue to run our business with the same rigorous financial discipline, prioritising the highest returns and focusing on value-accretive investments. Our balance sheet will continue to strengthen as we further reduce our debt and optimise our capital structure. We have made good progress toward delivering our target of $800 million of free cash flow between 2023 and 2025 and given the quality of our resource base, the opportunity set ahead of us and a reducing cost outlook, we expect to maintain these levels of free cash flow generation in subsequent years.

With a strong balance sheet and this sustainable free cash flow outlook, our business will be well placed to deliver value to our shareholders through organic and inorganic growth and capital returns.

I thank our shareholders for their continued support as we realise value across the portfolio in 2024 and beyond.

FINANCE REVIEW

Income Statement

Income Statement (key metrics)	2023	2022
Revenue ($m)		
Sales volume (boepd)	55,754	55,170
Realised oil price ($/bbl)	77.5	88.0
Total revenue	1,634	1,783
Operating costs ($m)		
Underlying cash operating costs[1]	(293)	(267)
Depreciation, Depletion and Amortisation (DDA) of oil and gas and leased assets	(431)	(411)
DDA before impairment charges ($/bbl)	18.8	18.4
(Overlift)/Underlift and oil stock movements	(109)	46
Administrative expenses	(56)	(51)
Gain on bargain purchase	-	197
Exploration costs written off	(27)	(105)
Impairment of property, plant and equipment, net	(408)	(391)
Gain on bond buyback	86	-
Net financing costs	(286)	(293)
Profit from continuing activities before tax	96	442
Income tax expense	(206)	(393)
(Loss)/Profit for the year from continuing activities	(110)	49
Adjusted EBITDAX[1]	1,151	1,469
Basic (loss)/earnings per share (cents)	(7.6)	3.4

1. Alternative performance measures are reconciled on pages 32 to 35.

Revenue

Sales Oil Volumes

During the year, there were 55,754 boepd (2022: 55,170 boepd) of liftings. The total number of liftings in Ghana is comparable to the previous year with 13 in Jubilee (2022: 12) and 4 in TEN (2022: 5).

Realised oil price ($/bbl)

The Group's realised oil price after hedging for the period was $77.5/bbl and before hedging $84.3/bbl (2022: $88.0/bbl and before hedging $104.3/bbl). Lower oil prices compared to 2022 have resulted in a lower hedge loss decreasing total revenue by $139 million in 2023 (2022: decrease of $319 million).

Gas sales

Included in Total Revenue of $1,634 million is gas sales of $38 million of which $29 million relates to Ghana. During the year, Ghana exported 35,754 mmscf (gross) of gas at an average price of $1.54/mmbtu.

Refer to Operational Performance section above for detailed gas pricing.

Cost of Sales

Underlying cash operating costs

Underlying cash operating costs amounted to $293 million; $12.8/boe (2022: $267 million; $11.9/boe). Routine operating costs largely remain unchanged from prior year. The increase in the current year is largely due to non-recurring expenditure.

Depreciation, depletion and amortisation

DD&A charges before impairment on production and development assets amounted to $431 million; $18.8/boe (2022: $411 million: $18.4/boe). This increase in DD&A per barrel is mainly attributable to downward revision of TEN and Espoir 2P reserves offset by 2022 impairments.

Overlift and oil stock movements

The overlift expense is caused by a decrease in the underlift position in Ghana due to timing of liftings as well as reduced stock positions in Gabon from higher sales volumes.

Administrative expenses

With the exception of the one-off corporate project expenditure which was partially offset by lower insurance premiums in the current year, Tullow has managed to maintain administrative expenses at prior year levels despite the inflationary environment.

Exploration costs written off

During 2023, the Group has written off exploration costs of $27 million (2022: $105 million) predominantly driven by Kenya where withdrawal of the JV Partners led to a re-assessment of risks associated to reaching FID resulting in a $17.9 million impairment and write-offs of $3.3 million in Cote d'Ivoire, $3.4 million for the Akoum B well in Gabon and $2.5 million in Guyana.

Impairment of property, plant and equipment

The Group recognised a net impairment charge on PP&E of $408 million in respect of 2023 (2022: $391 million) largely driven by a reduction in TEN reserves partially offset by oil price and updated cost assumptions. This was primarily due to delays in gaining approval for the amended TEN PoD which has led to the deferral of investment and continued field decline. There was also an impairment charge in Espoir due to an increase in cost assumptions. Refer to note 15 for the full year end 2023 audited reserve and resource position. There were also changes to estimates on the cost of decommissioning for certain UK and Mauritania assets.

Gain on bond buyback - refer to Borrowings section below.

Net financing costs

Net financing costs for the period were $286 million (2022: $293 million). This decrease is mainly due to lower interest of $13 million due to the bond redemption where interest was applied on lower outstanding bonds partially offset by an increase in the unwinding of discount on decommissioning provision in Ghana of $4 million.

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

Taxation

The overall net tax expense of $206 million (2022: $393 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 $96 million (2022: $442 million), the effective tax rate is 214.3 per cent (2022: 88.9 per cent). After adjusting for non-recurring amounts related to gain on bond buybacks, exploration write-offs, disposals, impairments, provisions and their associated deferred tax benefit, the Group's adjusted tax rate is 70.2 per cent (2022:70.3 per cent). 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 $167m (2022: $570m) 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	2023	584.4	(210.1)	35.9%
	2022	994.8	(359.7)	36.2%
Gabon	2023	216.0	(101.2)	46.8%
	2022	*316.1*	*(158.9)*	*50.3%*
Corporate	2023	(379.4)	9.6	2.5%
	2022	*(584.5)*	*3.5*	*0.6%*
Other non-operated & exploration	2023	1.5	4.7	-324.2%
	2022	*15.9*	*(6.9)*	*43.5%*
Total	**2023**	**422.5**	**(296.9)**	**70.2%**
	2022	***742.3***	***(522.1)***	***70.3%***

Adjusted EBITDAX

Adjusted EBITDAX for the year was $1,151 million (2022: $1,469 million). The decrease from 2022 was predominantly due to lower revenues associated with reduced oil prices.

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

The loss for the year from continuing activities amounted to $110 million (2022: $49 million profit). Loss after tax was driven mainly by impairments and write-offs totalling $435 million. Basic loss per share was 7.6 cents (2022: 3.4 cents earnings per share).

Balance Sheet and Liquidity management

Balance Sheet and Liquidity management (key metrics)	2023	2022
Capital investment ($m)[1]	380	354
Derivative financial instruments ($m)	(35)	(244)
Borrowings ($m)	(2,085)	(2,473)
Underlying operating cash flow ($m) [1]	813	972
Free cash flow ($m)[1]	170	267
Net debt ($m)[1]	1,608	1,864
Gearing (times)[1]	1.4	1.3

1. Alternative performance measures are reconciled on pages 32 to 35.

Capital Investment

Capital expenditure amounted to $380 million (2022: $354 million) with $356 million invested in production and development activities of which $288 million was invested in Jubilee mainly comprising of $173 million spend on drilling costs and $75 million on Jubilee South East (JSE) and $24 million invested in exploration and appraisal activities.

The Group's 2024 capital expenditure is expected to be c.$250 million and is expected to comprise Ghana of c.$160 million, West African Non-Operated of c.$60 million, Kenya of c.$10 million and exploration spend of c.$20 million.

Decommissioning

Decommissioning expenditure was $67 million in 2023 (2022: $72 million). The Group's decommissioning budget in 2024 is c.$70 million of which c.$20 million is provisioning for future decommissioning in Ghana and Gabon. Subject to programme scheduling, at the end of 2024 it is expected that c.$40 million of decommissioning liabilities in the UK and Mauritania will remain.

Derivative financial instruments

Tullow 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 2023, Tullow's hedge portfolio provides downside protection for c.60% of forecast production entitlements in the first half of 2024 with c.$57/bbl weighted average floors; for the same period, c.40% of forecast production entitlements is capped at weighted average sold calls of c.$77/bbl. In the second half of 2024, Tullow's hedge portfolio provides downside protection for c.45% of forecast production entitlements with c.$60/bbl weighted average floors; for the same period, c.20% of forecast production entitlements is capped at weighted average sold calls of c.$113/bbl.

For the period from June to December 2024, Tullow's hedge portfolio also includes three-way collars (with call spreads) with weighted average sold calls of c.$85/bbl and weighted average bought calls of c.$94/bbl, providing full access to oil price upside beyond the bought call price on c.10% of forecast production entitlements in this period.

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 (2022: Level 2). There were no transfers between fair value levels during the year.

At 31 December 2023, the Group's derivative instruments had a net negative fair value of $35 million (2022: net negative $244 million).

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

1H24 hedge portfolio at 31 December 2023	bopd	Bought put (floor)	Sold call	Bought call
Straight puts	11,217	$60.05	-	-
Collars	24,344	$55.37	$77.47	-
Three- way collars (call spread)	332	$60.00	$105.60	$114.53
Total/Weighted Average	**35,893**	**$56.88**	**$77.85**	**$114.53**

2H24 hedge portfolio at 31 December 2023	bopd	Bought put (floor)	Sold call	Bought call
Straight puts	6,250	$59.96	-	-
Collars	12,650	$60.36	$113.45	-
Three- way collars (call spread)	6,500	$60.00	$84.61	$93.55
Total/Weighted Average	**25,400**	**$60.17**	**$103.66**	**$93.55**

Since the start of 2024, the Company has added a further c.4kbopd of c.$60/bbl downside protection for the second half of 2024 with a combination of straight puts and three-way collars with weighted average call spreads of c.$79-$89/bbl.

Borrowings

On 15 May 2023, the Group made a mandatory prepayment of $100 million of the Senior Secured Notes due 2026.

On 20 June 2023, the Group repurchased $167 million nominal value of Senior Notes due 2025 for $100 million cash consideration through an Unmodified Dutch Auction. A gain on early bond redemption of $65 million is recognised as other income in the income statement.

On 13 November 2023, Tullow announced that it had entered into a $400 million five-year notes facility agreement with Glencore Energy UK limited (Glencore). The facility is available for 18 months and proceeds are to be used for liability management of the Senior Notes due 2025.

On 1 December 2023, the Group repurchased $115 million nominal value of Senior Secured Notes due 2026 for $103 million cash consideration through an Unmodified Dutch Auction. A gain on early bond redemption of $11 million is recognised as other income in the income statement.

On 20 December 2023, the Group repurchased $141 million nominal value of Senior Notes due 2025 for $130 million cash consideration through a Modified Dutch Auction. The cash consideration was funded through an equivalent drawdown under the Glencore facility. A gain on early bond redemption of $10 million is recognised as other income in the Income Statement.

The Group's total drawn debt reduced to $2.1 billion, consisting of $493 million nominal value Senior Notes due in March 2025, $1,485 million nominal value Senior Secured Notes due in May 2026 and $130 million outstanding under the Glencore facility.

Management regularly reviews options for optimising the Group's capital structure and may seek to retire or purchase outstanding debt from time to time through cash purchases or exchanges in the open market or otherwise.

Credit Ratings

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

On 21 June 2023, following completion of a bond tender announced on 12 June 2023, S&P's downgraded Tullow's corporate credit rating to CCC+ with stable outlook, from B- with negative outlook, and the rating of the Senior Secured Notes due 2026 to CCC+ from B- and the rating of the Senior Notes due 2025 to CCC from CCC+.

On 21 December 2023, following completion of the bond tenders announced on 15 November 2023, S&P's upgraded Tullow's corporate credit rating to B- with negative outlook, and the rating of the Senior Secured Notes due 2026 to B- and the rating of the Senior Notes due 2025 to CCC+.

On 22 December 2023, Moody's affirmed Tullow's corporate credit rating at Caa1, with negative outlook, and the rating of the Senior Secured Notes due 2026 at Caa1 and the rating of the Senior Notes due 2025 at Caa2.

Underlying Operating Cash Flow and Free Cash Flow

Underlying operating cash flow amounted to $813 million (2022: $972 million). The decrease of $159 million is due to decrease in net revenue of $201 million driven by lower oil prices and higher tax payments of $21 million partially offset by lower Gabon royalty payments of $28 million and a one-off payment in 2022 of $77 million relating to a historic dispute that has now been settled.

Free cash flow has decreased to $170 million (2022: $267 million) primarily due to a decrease in underlying operating cash flow of $159 million as explained above. There has been a decrease in net cash used in investing activities of $59 million mainly due to the one-off Ghana pre-emption payment and Uganda FID consideration receipt in 2022 but this has been offset by an increase in decommissioning spend of $14 million in the current period.

Net Debt and Gearing

Reconciliation of net debt	$m
FY 2022 net debt	**1,864**
Sales revenue	(1,634)
Operating costs	293
Other operating and administrative expenses	279
Operating cash flow before working capital movements	(1062)
Movement in working capital	(89)
Tax paid	275
Purchases of intangible exploration and evaluation assets and property, plant and equipment	292
Other investing activities	(24)
Other financing activities	435
Gain on bond buyback	(86)
Foreign exchange loss on cash	3
FY 2023 net debt	**1,608**

Net debt reduced by $256 million during the year to $1,608 million at 31 December 2023 (2022: $1,864 million), due to generation of free cash flow of $170 million (as explained above) as well as the gains on the three bond buybacks totalling $86 million.

The Gearing ratio has increased to 1.4 times (2022:1.3 times) due to a decrease in Adjusted EBITDAX as explained above primarily due to lower revenues associated with reduced oil prices. This is in line with our target to reach gearing of less than 1.5 times by year-end 2023.

Liquidity Risk Management and Going concern

The Directors consider the going concern assessment period to be up to 31 March 2025. The Group closely monitors and manages its liquidity headroom. Cash forecasts are regularly produced, and sensitivities run for different scenarios 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.

Management has applied the following oil price assumptions for the going concern assessment:

- Base Case: $78/bbl for 2024, $75/bbl for 2024; and
- Low Case: $70/bbl for 2024, $70/bbl for 2025.

The Low Case includes, amongst other downside assumptions, a 10% production decrease and 10% 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 $48 million outflow being included for the cases expected to progress in the period under assessment. The low case does not include the outflow for the full exposure on Ghana BPRT arbitration of $320 million (refer to note 7 Ghana tax assessments for details).The remaining arbitration cases are not expected to conclude within the going concern period and no outflows have been included in that respect.

At 31 December 2023, the Group had $1.0 billion liquidity headroom consisting of c.$0.5 billion free cash and $0.5 billion available under the revolving credit facility.

The Group or its affiliates may, at any time and from time to time, seek to retire or purchase outstanding debt through cash purchases and/or exchanges, in open-market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will be upon such terms and at such prices as management may determine, and will depend on prevailing market conditions, liquidity requirements, contractual restrictions, and other factors. The amounts involved may be material. The Group has repaid $0.3 billion and $0.2 billion of the 2025 and 2026 Notes, respectively, during the year. The repayment of the 2025 Notes was partially funded by a drawdown of $130 million of the Glencore facility.

The Group's forecasts show that the Group and Parent Company will be able to operate within its current debt facilities and have sufficient financial headroom for the going concern assessment period under its Base Case and Low Case at the end of the going concern period, including a full drawdown of the Glencore debt facility to support the payment of the 2025 Notes. The Directors have also performed a reverse stress test to establish the average oil price throughout the going concern period required to reduce headroom to zero, that price was determined to be $45/bbl. Based on the analysis above, the Directors have a reasonable expectation that the Group and Parent Company has adequate resources to continue in operational existence for the foreseeable future. Thus, they have adopted the going concern basis of accounting in preparing these Annual Results and Accounts.

Events since 31 December 2023

Gabon

On 29 February 2024, Tullow completed the Asset Swap agreement (ASA) transaction (discussed in note 11. Assets and liabilities classified as held for sale) with Perenco Oil and Gas Gabon S.A (Perenco). The transaction is a cashless asset swap to be achieved through the exchange of participating interests held by both parties in certain licences in Gabon. Management have determined that the acquisition of the additional interest in the Tchatamba licence is a Business Combination and the financial impacts cannot be disclosed in the Annual Report and Accounts as the measurement of the assets acquired is now underway. Accordingly, the relevant disclosure will be made in the 2024 half year results.

Kenya

On 1 March 2024 Tullow received a letter from the EPRA extending the review period of the updated Field Development Plan to 30 June 2024.

There have not been any other events since 31 December 2023 that have resulted in a material impact on the year-end results.

Responsibility statement

(DTR 4.2 and the Transparency (Directive 2004/109/EC) Regulations (as amended))

The Directors confirm that to the best of their knowledge:

a. the condensed set of financial statements has been prepared in accordance with IAS 34 'Interim Financial Reporting' as adopted by the UK and EU and IAS 34 'Interim Financial Reporting' as adopted by the EU, the Disclosure Guidance and Transparency Rules of the United Kingdom's Financial Conduct Authority (DTR) and the Transparency (Directive 2004/109/EC) Regulations 2007 as amended
b. the interim management report includes a fair review of the information required by DTR 4.2.7R and Regulation 8(2) (indication of important events during the first six months and description of principal risks and uncertainties for the remaining six months of the year); and
c. the interim management report includes a true and fair review of the information required by DTR 4.2.8R and Regulation 8(3) (disclosure of related parties' transactions and changes therein).

A list of the current Directors is maintained on the Tullow Oil plc website: www.tullowoil.com.

By order of the Board,

Rahul Dhir

Chief Executive Officer

5 March 2024

Richard Miller

Chief Financial Officer

5 March 2024

Disclaimer

This statement contains certain forward-looking statements that are subject to the usual risk factors and uncertainties associated with the oil and gas exploration and production business. Whilst the Group believes the expectations reflected herein to be reasonable in light of the information available to them at this time, the actual outcome may be materially different owing to factors beyond the Group's control or within the Group's control where, for example, the Group decides on a change of plan or strategy. Accordingly, no reliance may be placed on the figures contained in such forward-looking statements.

Group income statement

Year ended 31 December 2023

$m	Notes	2023	2022
Continuing activities			
Revenue		1,634.1	1,783.1
Cost of sales	5	(869.2)	(697.5)
Gross profit		764.9	1,085.6
Administrative expenses	5	(56.1)	(51.0)
Gain on bargain purchase		–	196.8
Other gains		0.2	3.1
Exploration costs written off	8	(27.0)	(105.2)
Impairment of property, plant and equipment, net	9	(408.1)	(391.2)
Provisions reversal/ (expense)	5	22.0	(4.2)
Operating profit		295.9	733.9
(Loss)/ gain on hedging instruments		(0.4)	0.8
Gain on bond buyback		86.0	–
Finance income	6	44.0	42.9
Finance costs	6	(329.6)	(335.5)
Profit from continuing activities before tax		95.9	442.1
Income tax expense	7	(205.5)	(393.0)
(Loss)/ profit for the year from continuing activities		(109.6)	49.1
Attributable to			
Owners of the Company		(109.6)	49.1
(Loss)/ earnings per ordinary share from continuing activities		¢	¢
Basic		(7.6)	3.4
Diluted		(7.6)	3.3

Group statement of comprehensive income and expense

Year ended 31 December 2023

$m	2023	2022
(Loss)/ profit for the year	(109.6)	49.1
Items that may be reclassified to the income statement in subsequent periods		
Cash flow hedges		
Gains/ (losses) arising in the year	20.1	(399.5)
Gains arising in the year – time value	50.3	21.7
Reclassification adjustments for items included in profit on realisation	111.3	288.5
Reclassification adjustments for items included in loss on realisation – time value	27.8	30.8
Exchange differences on translation of foreign operations	(5.8)	10.2
Other comprehensive income/ (expense)	203.7	(48.3)
Tax relating to components of other comprehensive income/ (expense)	–	–
Net other comprehensive income/ (expense) for the year	203.7	(48.3)
Total comprehensive income for the year	94.1	0.8
Attributable to		
Owners of the Company	94.1	0.8

Group balance sheet

As at 31 December 2023

$m	Notes	2023	2022
Assets			
Non-current asset			
Intangible exploration and evaluation assets	8	287.0	288.6
Property, plant and equipment	9	2,532.8	2,981.4
Other non-current assets	10	338.6	327.1
Deferred tax assets		19.6	14.5
		3,178.0	3,611.6
Current assets			
Inventories		107.3	181.6
Trade receivables		43.5	26.8
Other current assets	10	571.2	567.9
Current tax assets		3.8	15.4
Cash and cash equivalents		499.0	636.3
Assets classified as held for sale	11	55.8	–
		1,280.6	1,428.0
Total assets		4,458.6	5,039.6
Liabilities			
Current liabilities			
Trade and other payables	12	(775.0)	(750.2)
Borrowings		(100.0)	(100.0)
Provisions	14	(67.9)	(98.8)
Current tax liabilities		(230.5)	(186.0)
Derivative financial instruments		(35.0)	(186.3)
Liabilities associated with assets classified as held for sale	11	(17.6)	–
		(1,226.0)	(1,321.3)
Non-current liabilities			
Trade and other payables	12	(783.2)	(780.0)
Borrowings		(1,984.6)	(2,372.8)
Provisions	14	(403.7)	(415.6)
Deferred tax liabilities		(420.5)	(551.5)
Derivative financial instruments		–	(57.9)
		(3,592.0)	(4,177.8)
Total liabilities		(4,818.0)	(5,499.1)
Net liabilities		(359.4)	(459.5)
Equity			
Called-up share capital		216.7	215.2
Share premium		1,294.7	1,294.7
Foreign currency translation reserve		(244.4)	(238.6)
Hedge reserve		(18.9)	(150.3)
Hedge reserve – time value		(16.3)	(94.4)
Merger reserve		755.2	755.2
Retained earnings		(2,346.4)	(2,241.3)
Equity attributable to equity holders of the Company		(359.4)	(459.5)
Total equity		(359.4)	(459.5)

Group statement of changes in equity

Year ended 31 December 2023

$m	Share capital	Share premium	Foreign currency translation reserve[1]	Hedge reserve[2]	Hedge reserve – time value[2]	Merger reserves	Retained earnings	Total
At 1 January 2022	214.2	1,294.7	(248.8)	(39.3)	(146.9)	755.2	(2,295.2)	(466.1)
Profit for the year	–	–	–	–	–	–	49.1	49.1
Hedges, net of tax	–	–	–	(111.0)	52.5	–	–	(58.5)
Currency translation adjustments	–	–	10.2	–	–	–	–	10.2
Exercise of employee share options	1.0	–	–	–	–	–	(1.0)	–
Share-based payment charges	–	–	–	–	–	–	5.8	5.8
At 1 January 2023	215.2	1,294.7	(238.6)	(150.3)	(94.4)	755.2	(2,241.3)	(459.5)
Loss for the year	–	–	–	–	–	–	(109.6)	(109.6)
Hedges, net of tax	–	–	–	131.4	78.1	–	–	209.5
Currency translation adjustments	–	–	(5.8)	–	–	–	–	(5.8)
Exercise of employee share options	1.5	–	–	–	–	–	(1.5)	–
Share-based payment charges	–	–	–	–	–	–	6.0	6.0
At 31 December 2023	216.7	1,294.7	(244.4)	(18.9)	(16.3)	755.2	(2,346.4)	(359.4)

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.

Group cash flow statement

Year ended 31 December 2023

$m	Notes	2023	2022
Cash flows from operating activities			
Profit from continuing activities before tax		95.9	442.1
Adjustments for:			
Depreciation, depletion and amortisation	9	436.6	425.8
Gain on bargain purchase		–	(196.8)
Other gains		(0.2)	(3.1)
Taxes paid in kind	7	(11.0)	(21.4)
Exploration costs written off	8	27.0	105.2
Impairment of property, plant and equipment, net	9	408.1	391.2
Provisions (reversal)/ expense		(22.0)	4.2
Payment for provisions	14	(0.6)	(127.3)
Decommissioning expenditure	14	(78.1)	(57.7)
Share-based payment charge		6.0	5.8
Loss/ (gain) on hedging instruments		0.4	(0.8)
Gain on bond buyback		(86.0)	
Finance income	6	(44.0)	(42.9)
Finance costs	6	329.6	335.5
Operating cash flow before working capital movements		1,061.7	1,259.8
(Increase)/ decrease in trade and other receivables		(36.3)	288.4
Decrease/ (increase) in inventories		66.6	(48.0)
Increase/ (decrease) in trade payables		58.7	(193.1)
Cash generated from operating activities		1,150.7	1,307.1
Income taxes paid		(274.5)	(229.3)
Net cash from operating activities		876.2	1,077.8
Cash flows from investing activities			
Proceeds from disposals		0.7	68.1
Purchase of additional interest in joint operation		–	(126.8)
Purchase of intangible exploration and evaluation assets		(30.2)	(42.6)
Purchase of property, plant and equipment		(262.3)	(263.8)
Interest received		23.3	8.9
Net cash used in investing activities		(268.5)	(356.2)
Cash flows from financing activities			
Debt arrangement fees		(5.0)	–
Repayment of borrowings		(432.2)	(100.0)
Drawdown of borrowings		129.7	–
Payment of obligations under leases	13	(195.0)	(203.8)
Finance costs paid		(240.0)	(249.0)
Net cash used in financing activities		(742.5)	(552.8)
Net (decrease)/ increase in cash and cash equivalents		(134.8)	168.8
Cash and cash equivalents at beginning of year		636.3	469.1
Foreign exchange loss		(2.5)	(1.6)
Cash and cash equivalents at end of year		499.0	636.3

NOTES TO THE FINANCIAL STATEMENTS

Year ended 31 December 2023

1. Basis of preparation and presentation of financial information

The Financial Statements have been prepared in accordance with UK-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 2023 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 2022 have been delivered to the Registrar of Companies and those for 2023 will be delivered following the Company's annual general meeting. The auditor has reported on these accounts; their reports were unqualified. Their report did not include a reference to any other matters to which the auditor drew attention by way of emphasis of matter and did not contain a statement under section 498 (2) or (3) of the Companies Act 2006.

The 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 2022. 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 2023, 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 2023 Annual Report and Accounts.

Certain new accounting standards and interpretations have been published that are not mandatory for 31 December 2023 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. (Loss)/earnings per ordinary share

Basic (loss)/earnings per ordinary share amounts are calculated by dividing net (loss)/profit 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 (loss)/profit 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. 2023 Annual Report and Accounts

The 2023 Annual Report and Accounts will be mailed in March 2024 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 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 including Uganda 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, loss and certain asset and liability information regarding the Group's reportable business segments for the years ended 31 December 2023 and 31 December 2022.

$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
Provisions reversal						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)
Loss 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, impairment of property, plant and equipment. See reconciliation below.
2. Unallocated expenditure and 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	2023	2022
Segment result	329.8	589.2
Add back:		
Exploration costs written off	27.0	105.2
Impairment of Property, plant and equipment	408.1	391.2
Gross profit	764.9	1,085.6

4. Segmental reporting continued

$m	Ghana	Non-Operated	Kenya	Exploration	Corporate	Total
2022						
Sales revenue by origin	1,578.5	524.0	–	–	(319.4)	1,783.1
Segment result[1]	692.5	337.3	(0.5)	(102.6)	(337.5)	589.2
Provisions expense						(4.1)
Gain on bargain purchase						196.8
Other gains and losses						3.1
Unallocated corporate expenses[2]						(51.1)
Operating profit						733.9
Gain on hedging instruments						0.8
Finance income						42.9
Finance costs						(335.5)
Profit before tax						442.1
Income tax expense						(393.0)
Profit after tax						49.1
Total assets	3,827.7	380.6	265.6	46.0	519.7	5,039.6
Total liabilities[3]	(2,220.5)	(401.6)	(14.1)	(4.6)	(2,858.3)	(5,499.1)
Other segment information						
Capital expenditure:						
Property, plant and equipment	342.9	26.9	–	–	0.9	370.7
Intangible exploration and evaluation assets	0.9	(1.7)	(2.1)	42.1	–	39.2
Depletion, depreciation and amortisation	(362.1)	(52.7)	(1.3)	–	(9.7)	(425.8)
Impairment of property, plant and equipment, net	(380.6)	(10.6)	–	–	–	(391.2)
Exploration costs written off	(0.9)	1.8	(0.5)	(105.6)	–	(105.2)

1. Segment result is a non IFRS measure which includes gross profit, exploration costs written off, impairment of property, plant and equipment. See reconciliation above.
2. Unallocated expenditure and 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.

5. Other costs

$m	2023	2022
Cost of sales		
Operating costs	292.9	266.5
Depletion and amortisation of oil and gas and leased assets[1]	430.8	410.7
Overlift, underlift and oil stock movements	109.3	(46.3)
Royalties	33.9	61.7
Share-based payment charge included in cost of sales	0.4	0.4
Other cost of sales	1.9	4.4
Total cost of sales	869.2	697.5
Administrative expenses		
Share-based payment charge included in administrative expenses	5.6	5.4
Depreciation of other fixed assets	5.8	15.1
Other administrative costs	44.7	30.5
Total administrative expenses	56.1	51.0
Provisions (reversal)/ expense[2]	(22.0)	4.2

1. Depreciation expense on leased assets of $81.4 million as per note 9 includes a charge of $2.2 million on leased administrative assets, which is presented within administrative expenses in the income statement. The remaining balance of $79.2 million relates to other leased assets and is included within cost of sales.

   The reduction in depreciation of other fixed assets expense is caused by corporate assets in the UK and Ghana reaching the end of their useful life during 2022 and 2023.
2. This includes credit to the movements in other provisions of $22.0 million (2022: $4.1 million charge) as well as restructuring and redundancy costs of $nil (2022: $0.1 million).

The increase in other administrative costs is mainly due to one-off corporate project spend partially offset by lower insurance premiums in the current year.

6. Net financing costs

$m	2023	2022
Interest on bank overdrafts and borrowings	237.0	250.4
Interest on obligations for leases	78.6	76.4
Total borrowing costs	315.6	326.8
Finance and arrangement fees	1.9	0.3
Other interest expense	2.0	2.4
Unwinding of discount on decommissioning provisions	10.1	6.0
Total finance costs	329.6	335.5
Interest income on amounts due from Joint Venture partners for leases	(30.1)	(29.6)
Other finance income	(13.9)	(13.3)
Total finance income	(44.0)	(42.9)
Net financing costs	285.6	292.6

7. Taxation on profit on continuing activities

$m	2023	2022
Current tax on profits for the year		
UK corporation tax	(1.9)	(11.8)
Foreign tax	322.2	321.0
Taxes paid in kind under production sharing contracts	11.0	21.4
Adjustments in respect of prior periods	10.8	(3.3)
Total corporate tax	342.1	327.3
UK petroleum revenue tax	(0.7)	(2.8)
Total current tax	341.4	324.5
Deferred tax		
Origination and reversal of temporary differences		
UK corporation tax	(22.9)	11.4
Foreign tax	(106.5)	54.0
Adjustments in respect of prior periods	(2.8)	(2.9)
Total deferred corporate tax	(132.2)	62.5
Deferred UK petroleum revenue tax	(3.7)	6.0
Total deferred tax	(135.9)	68.5
Total income tax expense	205.5	393.0

$m	2023	2022
Profit from continuing activities before tax	95.9	442.1
Tax on profit from continuing activities at the standard UK corporation tax rate of 23.5% (2022: 19%)	22.5	84.0
Effects of:		
Non-deductible exploration expenditure	3.4	0.5
Other non-deductible expenses	35.4	27.8
Net deferred tax asset not recognised	65.1	138.5
Utilisation of tax losses not previously recognised	(0.2)	(0.4)
Adjustment relating to prior years	(2.8)	(6.2)
Other tax rates applicable outside the UK	82.4	214.6
Other income not subject to corporation tax	(0.3)	(0.1)
Tax impact of acquisition through business combination	–	(65.7)
Group total tax expense for the year	205.5	393.0

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.

7. Taxation on profit on continuing activities continued

Uncertain tax treatments continued

Provisions of $85.0 million (2022: $106.4 million) are included in income tax payable ($78.3 million (2022: $70.6 million)) and provisions ($6.7 million (2022: $35.8 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 within 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 of these claims, the result would be additional liabilities of $1,030.3 million (2022: $1,024.0 million) which includes $6.9 million of interest and penalties (2022: $32.4 million).

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 2023, giving rise to an overall decrease in provision of $21.4 million and increase in contingent liability of $6.2 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. The arbitration hearing took place in October 2023 and a decision is expected in the current financial year. TGL is not required to pay any amounts of BPRT until the dispute is formally resolved.

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 arbitration hearing is scheduled to commence on 30 June 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 arbitration hearing is scheduled to commence on 17 November 2025.

The Group continues to engage with the Government of Ghana with the aim of resolving the BPRT, loan interest and insurance disputes on a mutually acceptable basis.

Bangladesh litigation

The National Board of Revenue (NBR) is seeking to disallow $118.6 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 3,094.3 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. A procedural hearing was held on 28 June 2022 which set the timetable for the process going forward. The first submissions have been made in October 2022 with counter submissions received on 17 January 2023. The second submission was made in June 2023 with the first Tribunal hearing scheduled for 20-24 May 2024. A decision is expected in H1 2025.

Other items

Other items totalling $294.0 million (2022: $280.0 million) comprise exposures in respect of claims for corporation tax in respect of disallowed expenditure or withholding taxes that are either currently under discussion with the tax authorities or which arise in respect of 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, as they are subject to outcome of court / arbitration proceedings and any potential appeals, 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	2023	2022
At 1 January	288.6	354.6
Additions	25.4	39.2
Amounts written off	(27.0)	(105.2)
At 31 December	287.0	288.6

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

Country	CGU	Rationale for 2023 write-off	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.

Kenya

Discussions with the Government of Kenya (GoK) on securing government deliverables and 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 ends on 30 June 2024. The Group expects a production licence to be granted once government due process has been 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 transaction will be considered completed and Tullow will have full 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, who is the only remaining Joint Venture Partner.

In 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 Joint Operating Agreement, it is considered that the ownership of the 50% held by AOC and TE was passed on 30 June 2023, resulting in Tullow holding 100%. From that date, Tullow has the right to benefit from the PI and is liable for all costs incurred going forward (except those for which the withdrawing parties remain liable for). As the sole party, Tullow can control and direct the use of the asset from 30 June 2023. The position remained unchanged as at 31 December 2023. Tullow accounted for this as asset acquisition at nil cost.

The withdrawal of the partners and an upward revision to the Group's oil prices as detailed in note 9 are considered to be impairment assessment triggers for the asset as at 31 December 2023, and in line with its accounting policy the Group has performed a VIU assessment. The cash flows were discounted using a pre-tax nominal discount rate of 20% (2022: 20%). This resulted in an NPV significantly in excess of the book value of $260.1 million. However, the Group has identified the following uncertainties in respect of the Group's ability to realise the estimated VIU; receiving and subsequently finalising an acceptable offer from a strategic partner and securing governmental approvals relating thereto, obtaining financing for the project and government deliverables in form of provision of required infrastructure and fiscal terms. These items require satisfactory resolution before the Group can take a Final Investment Decision (FID). The Group continues to progress with the farm-down process.

8. Intangible exploration and evaluation assets continued

Kenya continued

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 VIU to determine a risk-adjusted VIU and compared against the net book value of the asset. Certain risks have increased since 31 December 2022, predominantly around farm-down and project financing. This has been partially offset by an increased equity interest in the project and changes in oil price assumptions.

Based on this, the NPV has been revised to $242.2 million and an impairment of $17.9 million has been recognised as at 31 December 2023.

Should the uncertainties around the project be resolved, there will be a reversal of a previously recorded impairment. However, if the uncertainties are not resolved there will be an additional impairment of $242.2 million. 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 $37.9 million, whilst increases to oil prices specified above would result in a credit to the impairment charge of $37.7 million. A 1% change in the pre-tax discount rate would result in an additional impairment charge of $33.9 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.

Guyana

On 10 August 2023, Tullow announced that it had agreed to sell its total interest in Tullow Guyana B.V., which includes the Orinduik licence (60% operated equity) in Guyana, to Eco Guyana Oil and Gas (Barbados) Limited in exchange for an upfront cash consideration of $0.7 million and contingent consideration linked to a series of potential future milestones.

The transaction completed on 16 November 2023 and resulted in $0.7 million of gain on disposal recognised in the income statement.

9. Property, plant and equipment

$m	2023 Oil and gas assets	2023 Other fixed assets	2023 Right of use assets	2023 Total	2022 Oil and gas assets	2022 Other fixed assets	2022 Right of use assets	2022 Total
Cost								
At 1 January	11,182.6	30.0	1,196.8	12,409.4	10,521.7	69.5	1,091.7	11,682.9
Additions	416.1	2.3	81.1	499.5	305.2	2.0	63.5	370.7
Acquisitions[1]	–	–	–	–	473.2	–	–	473.2
Transfer[1]	–	–	–	–	–	–	86.6	86.6
Transfer to assets held for sale	(302.8)	–	–	(302.8)	–	–	–	–
Asset retirement	(67.7)	(11.0)	(10.6)	(89.3)	–	(38.1)	(41.7)	(79.8)
Currency translation adjustments	53.9	0.6	1.5	56.0	(117.5)	(3.4)	(3.3)	(124.2)
At 31 December	11,282.1	21.9	1,268.8	12,572.8	11,182.6	30.0	63.5	370.7
Depreciation, depletion, amortisation and impairment								
At 1 January	(8,888.4)	(24.4)	(515.2)	(9,428.0)	(8,263.7)	(53.8)	(450.8)	(8,768.3)
Charge for the year	(351.6)	(3.6)	(81.4)	(436.6)	(353.7)	(11.2)	(60.9)	(425.8)
Impairment loss	(399.1)	–	(9.0)	(408.1)	(391.2)	–	–	(391.2)
Capitalised depreciation	–	–	(49.3)	(49.3)	–	–	(46.1)	(46.1)
Transfer to assets held for sale	247.6	–	–	247.6	–	–	–	–
Asset retirement	67.7	11.0	10.6	89.3	–	38.1	41.7	79.8
Currency translation adjustments	(53.9)	(0.5)	(0.5)	(54.9)	120.2	2.5	0.9	123.6
At 31 December	(9,377.7)	(17.5)	(644.8)	(10,040.0)	(8,888.4)	(24.4)	(515.2)	(9,428.0)
Net book value at 31 December	1,904.4	4.4	624.0	2,532.8	2,294.2	5.6	681.6	2,981.4

1. This relates to an acquisition through business combination discussed in note 15 of the 2022 Annual Report and Accounts.

9. Property, plant and equipment continued

During 2023 and 2022, 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
2023	$78/bbl	$75/bbl	$75/bbl	$75/bbl	$75/bbl	$75/bbl inflated at 2%
2022	$84/bbl	$79/bbl	$70/bbl	$70/bbl	$70/bbl	$70/bbl inflated at 2%

	Trigger for 2023 impairment	2023 Impairment $m	Pre-tax discount rate assumption	2023 Remaining recoverable amount [g] $m
Espoir (Côte 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 within those countries 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.

Impairments identified in the TEN fields of $301.2 million were primarily due to lower 2P reserves partially offset by an increase in oil price. This was primarily due to delays in gaining approval for the amended TEN PoD which has led to the deferral of investment and continued field decline.

Oil prices stated above are benchmark prices to which an individual field price differential is applied. All impairment assessments are prepared on a VIU basis using discounted future cash flows based on 2P reserves profiles. 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 $76.4 million for Ghana and increase the impairment by $0.4 million for Non-Operated, whilst increases to oil prices specified above would result in a reduction in the impairment charge of $72.6 million for Ghana and $17.1 million for Non-Operated. A 1% increase in the pre-tax discount rate would increase the impairment by $15.6 million for Ghana and increase the impairment by $0.4 million for Non-Operated. The Group believes a 1% increase in the pre-tax discount rate to be a reasonable possibility based on historical analysis of the Group's and peer group of companies' impairments.

10. Other assets

$m	2023	2022
Non-current		
Amounts due from Joint Venture Partners	332.5	323.3
VAT recoverable	6.1	3.8
	338.6	327.1
Current		
Amounts due from Joint Venture Partners	498.1	452.3
Underlifts	47.8	76.2
Prepayments	21.1	31.3
Other current assets	4.2	8.1
	571.2	567.9
	909.8	895.0

The increase in current receivables from JV Partners compared to December 2022 mainly relates to partner's share of increased accrual balances (note 12), net increase in GNPC (Ghana National Petroleum Corporation) receivable and other working capital movements, partially offset by a lower balance of current receivables relating to leases.

11. Assets and liabilities classified as held for sale

On 28 April 2023, Tullow announced that through its wholly owned subsidiary, Tullow Oil Gabon S.A., it had signed an Asset Swap Agreement (ASA) with Perenco Oil and Gas Gabon S.A. (Perenco). Under the ASA, Tullow has agreed to assign and transfer certain of its existing participating interests in Limande, Turnix, M'oba, Oba and 17.5% in Simba assets to Perenco in return for the assignment and transfer by Perenco of 15% of its participating interests in Kowe (Tchatamba) and 20% of its participating interests in DE8 licence to Tullow.

Due to the agreed neutrality of the transaction, no additional consideration is payable by either party in respect thereof. The ASA includes provisions to ensure the neutrality of the transaction via cash adjustments for the period between economic date and completion date.

On completion, all assets and associated liabilities relating to the existing participating interests held in Limande, Turnix, M'Oba and Oba assets, together with 17.5% of Tullow's interest in Simba, will be disposed. All assets impacted by the transaction are included in the 'Non-Operated' Business Unit applied for segment performance reporting.

Management concluded that the asset met the IFRS 5 Held for Sale criteria on 19 July 2023, when the agreed form of the amendment to the Tullow Protocol was submitted to the relevant Governmental Authority of the Gabonese Republic (the Tullow Protocol is an investment convention that applies to certain Tullow licences). All other conditions precedent to the completion of the transaction were considered reasonably certain to occur within 12 months of 19 July 2023.

The transaction completed on 29 February 2024. Refer to Events since 31 December 2023 in the Finance Review.

The major classes of assets and liabilities comprising the assets classified as held for sale as at 31 December 2023 were as follows:

$m	2023
Assets	
Property, plant and equipment	55.2
Other debtors	0.6
Assets classified as held for sale	55.8
Liabilities	(1.4)
Accruals	(2.0)
Decommissioning provision	(14.2)
Liabilities directly associated with assets classified as held for sale	(17.6)
Net assets directly associated with disposal group	38.2

12. Trade and other payables

$m	2023	2022
Current liabilities		
Trade payables	22.3	68.4
Other payables	65.3	51.4
Overlifts	3.1	–
Accruals	498.6	379.3
Current portion of lease liabilities	185.7	251.2
	775.0	750.2
Non-current liabilities		
Other non-current liabilities[1]	62.2	47.1
Non-current portion of lease liabilities	721.0	732.9
	783.2	780.0

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

Accruals mainly relate to capital expenditure, interest expense on bonds and staff-related expenses. The movement in the balance is predominantly driven by an increased level of activity in Ghana during the year relating to Jubilee South East.

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

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

The movement in current lease liabilities is mainly driven by the remeasurement of the TEN FPSO lease discussed in 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	2023	2022	2023	2022
Right-of-use assets (included within property, plant and equipment) and lease liabilities				
Property leases	22.0	39.2	27.6	34.6
Oil and gas production and support equipment leases	576.9	639.0	826.4	942.4
Transportation equipment leases	25.1	3.4	52.7	7.1
Total	624.0	681.6	906.7	984.1
Current provisions			185.7	251.2
Non-current			721.0	732.9
Total			906.7	984.1

Additions to the right-of-use assets during the 2023 financial year were $81.1 million. 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 the year, 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 within Property, plant and equipment)	25.6
Amounts due from Joint Venture Partners	13.6

13. Leases continued

As at 31 December 2023, the present value of the TEN FPSO right-of-use asset was $549.0 million (2022: $596.9 million).

The present value of the TEN FPSO gross lease liability was $763.5 million (2022: $847.9 million).

A receivable from the Joint Venture Partners of $288.8 million (2022: $330.1 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 within 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 2022	(1,163.4)	531.0	(632.4)
Additions and changes in lease estimates	(89.4)	40.2	(49.2)
Acquisitions	–	(86.6)	(86.6)
Payments/(receipts)	342.0	(138.2)	203.8
Interest (expense)/income	(76.4)	29.6	(46.8)
Currency translation adjustments	3.1	–	3.2
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 31 December	(906.7)	349.5	(557.2)

ii) Amounts recognised in the statement of profit or loss

$m	2023	2022
Depreciation charge of right-of-use assets		
Property leases	7.3	14.0
Oil and gas production and support equipment leases	74.1	46.9
Total	81.4	60.9
Interest expense on lease liabilities (included in finance costs)	78.6	76.4
Interest income on amounts due from Joint Venture Partners	(30.1)	(29.6)
Expense relating to short-term leases	1.0	2.0
Expense relating to leases of low-value assets	0.9	1.8
Total	131.8	111.5

The total net cash outflow for leases in 2023 was $195.0 million (2022: $203.8 million).

14. Provisions

$m	Decommissioning 2023	Other provisions 2023	Total 2023	Decommissioning 2022	Other provisions 2022	Total 2022
At 1 January	398.1	116.3	514.4	498.7	228.8	727.5
New provisions, changes in estimates and reclassifications	47.8	(21.9)	25.9	(47.6)	(19.7)	(67.3)
Acquisitions[1]	–	–	–	24.8	36.8	61.6
Transfer to assets and liabilities held for sale	(14.2)	–	(14.2)	–	–	–
Payments	(66.4)	(0.6)	(67.0)	(72.1)	(127.3)	(199.4)
Unwinding of discount	10.1	–	10.1	6.0	–	6.0
Currency translation adjustment	2.5	(0.1)	2.4	(11.6)	(2.3)	(13.9)
At 31 December	377.9	93.7	471.6	398.1	116.3	514.4
Current provisions	53.4	14.5	67.9	87.7	11.1	98.8
Non-current provisions	324.5	79.2	403.7	310.4	105.2	415.6

1. This relates to an acquisition through business combination discussed in note 15 of the 2022 Annual Report and Accounts.

Other provisions include non-income tax provisions of $38.8 million (2022: $68.3 million) and $54.9 million (2022: $48.0 million) of disputed cases and claims. Management estimates non-current other provisions would fall due between two and five years.

Non-Current other provisions includes 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 Company's interest.

The decommissioning provision represents the present value of decommissioning costs relating to the European 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.

In 2023, after the extension of several licences in Gabon, the discount rate has increased from 3.5% to 4% for those assets with an assumed cessation of production date post 2038. This is due to a rate difference between the 10- and 20-year US Treasury Bills which are used as a data source. This resulted in a decrease in the provision of $3.1 million in Gabon.

Decommissioning provisions	Inflation assumption[1]	Discount rate assumption 2023	Cessation of production assumption 2023	Total 2023 $m	Discount rate assumption 2022	Cessation of production assumption 2022	Total 2022 $m
Côte d'Ivoire	2%	3.5%	2032	47.1	3.5%	2035	45.6
Gabon	2%	3.5-4%	2034-2047	28.7	3.5%	2025-2037	49.2
Ghana	2%	3.5%	2032-2036	208.2	3.5%	2036	190.2
Mauritania	n/a	n/a	2018	54.7	n/a	2018	56.0
UK	n/a	n/a	2018	39.2	n/a	2018	57.1
				377.9			398.1

1. Short-term inflation rate assumption has decreased from 2.5% to 2.4% in 2024. Medium and long-term rates of 2% remained unchanged from 31 December 2022.

The Group's decommissioning activities are ongoing in the UK and Mauritania, with $53.4 of the future costs expected to be incurred in 2024. The remaining activities are planned to continue through to 2027, with an associated expenditure of $40.4 million.

15. Commercial Reserves and Contingent Resources summary working interest basis

	Ghana		Non-Operated		Kenya[6]		Exploration		Total		
	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf[8]	Petroleum mmboe
COMMERCIAL RESERVES[1]											
1 January 2023	164.3	157.3	37.8	5.1	-	-	-	-	202.1	162.4	229.1
Revisions[3,4]	(4.9)	8.4	7.0	2.8	-	-	-	-	2.1	11.2	4.0
Production	(15.5)	(14.0)	(4.9)	(1.1)	-	-	-	-	(20.4)	(15.1)	(22.9)
Acquisitions[5]	-	-	7.5	-	-	-	-	-	7.5	-	7.5
Disposals[7]	-	-	(5.5)	-	-	-	-	-	(5.5)	-	(5.5)
31 December 2023	143.8	151.7	41.9	6.8	-	-	-	-	185.8	158.5	212.2
CONTINGENT RESOURCES[2]											
1 January 2023	185.0	577.8	36.0	8.6	231.4	-	54.5	-	506.9	586.4	604.6
Revisions[3,4]	(32.2)	(66.8)	1.8	1.1	-	-	-	-	(30.4)	(65.7)	(41.4)
Acquisitions	-	-	3.2	-	239.0	-	-	-	242.2	-	242.2
Disposals[7]			(5.9)				(54.5)		(60.4)	-	(60.4)
31 December 2023	152.8	511.0	35.1	9.7	470.4	-	-	-	658.3	520.7	745.0
TOTAL											
31 December 2023	296.6	662.7	77.0	16.5	470.4	-	-	-	844.1	679.2	957.2

1. Reserves presented are 'Proven and Probable'. They are as audited and reported by independent third-party reserves auditor at YE 2023 and adjusted for production for January - December 2023.

2. Contingent Resources are 'Proven and Probable'. They are as audited and reported by independent third-party reserves auditor as at YE 2023 based on best available information.

3. Reserves and Resources revisions in Ghana relate to evaluation of the Jubilee South East (JSE) project, infill drilling and field performance in Jubilee during 2023, which is offset by the recategorisation of the Tweneboa oil project from reserves to contingent resource.

4. Reserves revisions in Gabon mainly relate to extension of Production licences except for Etame and Ezanga, maturation of Echira Infill wells and overall good field performance across all assets.

5. Reserves revisions in Gabon also include an asset swap with Perenco, in which M'Oba, Oba, Limande, Turnix and a percentage of Simba have been exchanged for an increased working interest in Tchatamba and the DE8 licence.

6. Kenya contingent resources have doubled to 470mmstb, with Tullow now holding 100% of the licence, and a Field Development Plan under discussion with government.

7. Guyana contingent resources have been removed following agreement with our JV Partner Eco and the expiry of the Kanuku licence.

8. A gas conversion factor of 6 mscf/boe is used to calculate the total Petroleum mmboe.

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 net entitlement reserves were 204.5 mmboe at 31 December 2023 (31 December 2022: 219.6 mmboe).

Contingent Resources relate to resources in respect of which development plans are in the course of preparation 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, Norwegian tax refund 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	2023	2022
Additions to property, plant and equipment	416.1	370.7
Additions to intangible exploration and evaluation assets	25.4	39.2
Less		
Changes to decommissioning asset estimate	47.8	(19.9)
Right-of-use asset additions	81.1	63.5
Lease payments related to capital activities	(53.6)	(40.2)
Additions to administrative assets	2.3	2.0
Other non-cash capital movements	(16.0)	50.4
Capital investment	**379.9**	354.1
Movement in working capital	(89.7)	(49.7)
Additions to administrative assets	2.3	2.0
Cash capital expenditure per the cash flow statement	**292.5**	306.4

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 within 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.

$m	2023	2022
Borrowings	2,084.6	2,472.8
Non-cash adjustments	22.8	27.2
Less cash and cash equivalents	(499.0)	(636.3)
Net debt	**1,608.4**	1,863.7

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 (loss)/profit from continuing activities adjusted for income tax expense, finance costs, finance revenue, loss/(gain) on hedging instruments, gain on bargain purchase, other losses, depreciation, depletion and amortisation, share-based payment charge, restructuring costs,loss/(gain) on disposal, gain on bond buy back, exploration costs written off, impairment of property, plant and equipment net and provision (reversal)/ expense.

$m	2023	2022
(Loss)/Profit from continuing activities	(109.6)	49.1
Adjusted for		
Income tax expense	205.5	393.0
Finance costs	329.6	335.5
Finance revenue	(44.0)	(42.9)
Loss/(Gain) on hedging instruments	0.4	(0.8)
Gain on bargain purchase	-	(196.8)
Other gains	(0.2)	(0.4)
Depreciation, depletion and amortisation	436.6	425.8
Share-based payment charge	6.0	5.8
Provision (reversal)/expense	(22.0)	4.2
Gain on bond buy back	(86.0)	-
Exploration costs written off	27.0	105.2
Impairment of property, plant and equipment, net	408.1	391.2
Adjusted EBITDAX	1,151.4	1,468.9
Net debt	1,608.4	1,863.7
Gearing (times)	1.4	1.3

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 2022 and 2023, 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.

$m	2023	2022
Cost of sales	869.2	697.5
Add		
Lease payments related to operating activity	7.2	14.0
Less		
Depletion and amortisation of oil and gas and leased assets	430.8	410.7
Underlift, overlift and oil stock movements	109.3	(46.3)
Share-based payment charge included in cost of sales	0.4	0.4
Royalties	33.9	61.7
Other cost of sales	9.1	18.5
Underlying cash operating costs	292.9	266.5
Non-recurring costs[1]	(25.9)	(14.7)
Total normalised cash operating costs	267.0	251.8
Production (MMboe)	22.9	22.3
Underlying cash operating costs per boe ($/boe)	12.8	11.9
Normalised cash operating costs per boe ($/boe)	11.7	11.3

1. Non-recurring costs include riser remediation costs, facility projects costs, CSV (Construction Support Vessel) campaign costs and shutdown 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 from/(used) in investing activities, repayment of obligations under leases, finance costs paid and foreign exchange gain/(loss).

$m	2023	2022
Net cash from operating activities	876.2	1,077.8
Net cash used in investing activities	(268.5)	(356.2)
Repayment of obligations under leases	(195.0)	(203.8)
Finance costs paid	(240.0)	(249.0)
Foreign exchange loss	(2.5)	(1.6)
Free cash flow	170.2	267.2

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 repayments 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	2023	2022
Net cash from operating activities	876.2	1,077.8
Decommissioning expenditure	78.1	57.7
Lease payments related to capital activities	53.6	40.2
Repayment of obligations under leases	(195.0)	(203.8)
Underlying operating cash flow	812.9	971.9
Net cash from/(used in) investing activities	(268.5)	(356.2)
Decommissioning expenditure	(78.1)	(57.7)
Lease payments related to capital activities	(53.6)	(40.2)
Pre-financing cash flow	412.7	517.8