2021 Half Year Results

Tullow Oil plc
15 September 2021

TULLOW OIL PLC - 2021 HALF YEAR RESULTS

15 September 2021 – Tullow Oil (Tullow) announces its Half Year results for the six months ended 30 June 2021. Details of the presentation (virtual) and conference call are available on the last page of this announcement and online at www.tullowoil.com.

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

"Strong operational performance in the first half of the year and a transformational debt refinancing have put Tullow on a firm footing to deliver our Business Plan. Our West Africa production assets have performed well, and we are narrowing production guidance for 2021 to the upper end of the range. In Kenya, the revised development plan creates a robust project that has the potential to deliver material value to the Government of Kenya and other stakeholders. Through our operations, Tullow continues to deliver Shared Prosperity and to be an engine for economic and social change in the developing economies in which we work. Furthermore, by targeting Net Zero by 2030 and an emphasis on responsible operations, we are ensuring that the oil and gas resources of our host countries are developed efficiently and safely, whilst minimising our environmental impact."

2021 FIRST HALF RESULTS SUMMARY

- Group working interest production for the first half of 2021 averaged 61,230 boepd, in line with expectations.
- Good operational progress in Ghana; FPSOs delivering over 98% uptime; sustained increased water injection and gas offtake rates; first new well in drilling programme, J56 producer, came on stream delivering production rates ahead of expectations.
- Progress made on the delivery of Business Plan set out in November 2020, including target to become Net Zero by 2030.
- Revenue of $727 million; gross profit of $321 million; profit after tax of $93 million; underlying operating cash flow of $218 million and free cash flow of $86 million.
- Continued focus on costs results in reduced administrative expenses of $23 million in 1H21, down c.50% year-on-year.
- Capital investment of $101 million; decommissioning costs of $37 million. 1H21 operating costs averaged $12.9/bbl, a year-on-year increase primarily due to lower production and increased costs related to extended COVID-19 operating procedures.
- Net debt at 30 June 2021 of c.$2.3 billion; Gearing of 2.6x net debt/EBITDAX; liquidity headroom and free cash of $0.7 billion.
- Completion of comprehensive debt refinancing with $1.8 billion of five-year Senior Secured Notes issued and a new $500 million revolving credit facility.
- Completion of Equatorial Guinea and Dussafu Marin permit sales in March and June respectively, receiving $133 million.

KEY FINANCIAL RESULTS

	1H 2021	1H 2020
Sales revenue ($m)	727	731
Gross profit ($m)	321	164
Underlying cash operating cost per barrel ($/bbl)	12.9	11.0
Profit / (loss) after tax ($m)	93	(1,327)
Free cash flow ($m)	86	(213)
Net debt ($m)	2,290	3,019
Gearing (times)	2.6	3.0

2021 GUIDANCE

- Group working interest production narrowed upwards to 58,000-61,000 boepd following deferral of a Jubilee shut-down into 2022 and an increase in production from Simba in Gabon following acceleration of work into 2H21.
- Full year capital investment and decommissioning spend of c.$260 million and c.$90 million respectively.
- Full year underlying operating cashflow expected to be c.$0.6 billion assuming $60/bbl for the remainder of the year. Post all costs, Tullow forecasts full year free cash flow of c.$0.1 billion. If the oil price averages $70/bbl in 2H21, this would increase by c.$50 million.
- Tullow's free cash flow guidance includes an expected payment of $75 million from Total which would be triggered if a Final Investment Decision (FID) for the Lake Albert Development in Uganda occurs before the end of the year. Public announcements suggest good progress is being made in Uganda, with agreements recently in place to launch the Upstream and Pipeline projects, but if FID does not occur in 2021, the $75 million payment is expected in 2022.

STRATEGY & BUSINESS PLAN

2021 is a transition year for Tullow as the Group begins to deliver the 10-year Business Plan presented at its Capital Markets Day last November. Much has been achieved in the first half of the year and while the start of drilling in Ghana is one of the most tangible examples, the Group has also maintained cost discipline, allocated capital carefully to accelerate high-return projects such as Simba in Gabon and recently submitted a revised draft development plan for Kenya, the culmination of over a year's in-depth work. The issuance of $1.8 billion of Senior Secured Notes with a $500 million revolving credit facility in May 2021 placed Tullow on a much firmer financial footing and the Group now has a clear runway to invest appropriately in its assets to maximise their value and deliver its cash generative plan.

Over the past few months, Tullow has focused on further refining the plan for the 2021-2025 period with a base case capital expenditure of c.$1.3 to c.$1.5 billion during this period. This expenditure is self-funded and requires no additional borrowing. Revenues are protected by Tullow's comprehensive prudent hedging programme and the Group has flexibility to reduce expenditure in the event of a sustained oil price fall to $55/bbl or below.

Overall, from 2021-2025, Tullow's Business Plan will deliver growth in production, reserves and underlying value, along with material cash flow to support deleveraging which will see the Group reduce its gearing to below 1.5x by 2025.

Maximising value from producing assets

The Jubilee field has c.2 billion barrels of oil initially in place and to date, Tullow has produced less than half of the expected ultimate recovery. Accordingly, given the quality of the field, Jubilee provides a highly profitable investment opportunity over the 2021-2025 period through a combination of infill drilling, facilities expansion, and two sanctioned projects in the eastern part of the field – Jubilee North East and Jubilee South East.

The TEN fields have over 1 billion barrels of oil initially in place and to date, Tullow has produced less than a third of the expected ultimate recovery through the Enyenra and Ntomme fields. Since the 2020 Capital Markets Day, Tullow and its Partners have had the opportunity to deepen their understanding of the TEN area, and now have an improved view of the remaining potential. Accordingly, the JV Partners have evolved their forward strategy on TEN to concentrate on the biggest and most cost-effective "pools", particularly in the Greater Ntomme and Tweneboa ("GNT") area. Two strategically-positioned wells to be drilled in the near-term will help better define the overall resource base at TEN, with options to accelerate future development. The Group is also seeking to commercialise the significant non-associated gas resource in the TEN fields.

Tullow's non-operated production in Gabon and Cote d'Ivoire continue to provide positive cash flow through existing production, infrastructure-led exploration (ILX) and a number of diverse low-risk investment options and projects.

Value opportunities

In Kenya, the revised development plan has been commercially, technically and environmentally enhanced. Tullow and its Kenya Joint Venture (JV) Partners are actively seeking a strategic partner(s) for the next stage of the project to develop this discovered resource which has the potential to deliver material value to the Government of Kenya and the JV Partnership, as well as other stakeholders.

Tullow is focusing its exploration expertise on unlocking additional value from our asset base. In Ghana and Côte d'Ivoire, Tullow's team is maturing prospects around the TEN FPSO and subsea infrastructure as well as in the adjacent block, CI-524. In the emerging basins of Guyana and Argentina, Tullow is focused on limiting its capital exposure while also seeking to capitalise on its significant positions in both countries.

Tullow's purpose

The oil & gas industry is in flux as many companies allocate capital away from the upstream and divest assets. However, as long as global hydrocarbon demand exists, it is imperative that Africa's oil & gas assets are managed responsibly, efficiently and transparently and that oil & gas production in developing economies creates long-lasting economic and social benefits. Notwithstanding the focus on reducing the use of fossil fuels by society and through legislation, the oil & gas industry can be an engine of development in many developing economies, particularly in Africa. Tullow has a long and proud history in Africa and is well positioned to continue as a leader in the continent's oil & gas industry. With a target to achieve Net Zero by 2030 and an emphasis on responsible operations, Tullow will ensure that the oil & gas resources of its host countries are developed efficiently and safely while minimising the environmental impact. Through its work, Tullow will deliver Shared Prosperity and create value for our investors, staff, host nations and communities.

ESG

Net Zero 2030

Tullow is committed to becoming a Net Zero Company by 2030 on its Scope 1 and 2 emissions. Over the period, this will be achieved through a combination of decarbonising its operated assets in Ghana and pursuing a nature-based carbon removal programme.

Over the next three years, Tullow has defined plans to reduce its CO2/GHG emissions from its operations through an increase in the gas handling capacity on Jubilee and process modifications on TEN. These investments are included in the Group's Business Plan and will put the Group on track to eliminate routine flaring in Ghana by 2025.

To offset the residual difficult-to-abate carbon emissions, progress is being made in identifying nature-based carbon removal projects such as reforestation, afforestation and conservation projects in Ghana. Ongoing work includes project screening, feasibility and investment readiness assessments ahead of selecting projects that deliver carbon offsets and community benefits. Tullow has appointed Terra Global to carry out feasibility studies in Ghana to identify projects for future investment.

Governance – Board changes

In June, Tullow announced that Dorothy Thompson CBE, Non-Executive Chair, had decided to step down from Tullow's Board. An executive search firm was appointed soon after and the process to find Dorothy's replacement is progressing well. Tullow expects to announce its new Chair in the autumn.

Tullow has also announced today in a separate press release that Les Wood, Chief Financial Officer, has mutually agreed with the Board that he will step down from Tullow at the end of the first quarter of 2022.

OPERATIONAL REVIEW

Production

Group working interest production averaged 61,230 boepd in the first half of 2021, in line with expectations. Full year guidance has been narrowed to 58,000-61,000 boepd, towards the upper end of the range.

Group average working interest production	**1H 2021 actual (kboepd)**	**FY 2021 guidance (kboepd)**
Ghana	42.5	42.1
Jubilee	*25.1*	*26.4*
TEN	*17.4*	*15.7*
Equatorial Guinea	2.1	1.1
Gabon	14.8	15.3
Côte d'Ivoire	1.8	1.5
Total production	**61.2**	**60.0**

Ghana

Jubilee

Gross production from the Jubilee field averaged c.70,600 bopd (net: c.25,100 bopd) in the first half of the year, slightly ahead of expectations due to good facility uptime and well performance. Full year guidance for Jubilee has been slightly adjusted upwards to c.74,300 bopd (net: c.26,400 bopd) following the decision to move the planned maintenance shut-down into the first half of 2022. Shifting the shutdown by approximately six months is expected to maximise the amount of work achievable as gas enhancement works planned for 2023 can be brought forward and an expected easing in COVID-19 restrictions will allow for a more efficient work programme to be carried out in the planned shutdown period.

The 2021 drilling programme continues and the first well of the programme, the J-56 producer, came onstream in July 2021 delivering rates ahead of expectations. The second well, the J-55 water injector, is expected to be online in the next few weeks and will be paired with an existing production well. During August, the rig drilled the top hole of the next Jubilee producer well, J-57-P, which is expected to be completed and brought online in early 2022. As a result of the new wells, average production from Jubilee is expected to increase in the second half of the year before growing further in 2022 as the drilling campaign continues.

TEN

Gross production from the TEN fields averaged c.37,000 bopd (net: c.17,400 bopd) in the first half of the year. This is broadly in line with expectations. Full year gross production from TEN is expected to be c.33,200 bopd (net: c.15,700 bopd) reflecting the underlying decline in the field during the year. Drilling of the Ntomme gas injector well (Nt-06) reached total depth this month with completion expected to be finished in October. When tied in later this year, the well is expected to mitigate against further decline and keep production broadly flat into 2022.

Operational improvement plan

The operational improvement plan in Ghana is an important part of our strategy to optimise reservoir performance, address production decline and support long term stable production. The plan is delivering good results across the key areas of facility uptime, gas offtake and water injection. The two FPSOs averaged 98% uptime in the first half of 2021, gas offtake from the Government of Ghana is averaging c.110 mmscfd and improved Jubilee water injection rates continue to be in excess of 200 kbwpd.

Non-operated portfolio

Net production from the non-operated portfolio averaged c.18,700 boepd in the first half of 2021, with contributions from Gabon, Equatorial Guinea and Côte d'Ivoire. Following the sale of assets in Equatorial Guinea and the Dussafu Marin permit in Gabon net production from the portfolio for the full year is expected to be c.17,900 boepd.

Fields in Gabon continue to offer high-return and fast payback opportunities. As such, capital expenditure has been re-allocated to accelerate the Simba expansion and an appraisal well at Tchatamba, into 2021. As part of the Simba expansion, the Simba-3 production well was brought onstream in early September and is performing in line with expectations. The Tchatamba south appraisal well, brought forward from 2022, is currently being drilled, and subject to results, will enable the Tchatamba south east development to commence in 2022, a year earlier than initially planned.

As previously announced in Tullow's 2020 Full Year Results, following a major incident onboard the FPSO in the CNR International (CNR) operated Espoir field in mid-January 2021, production was shut in for approximately four weeks in the first half of the year. A further shut down of approximately two months is currently under way to carry out remediation work identified by BW Offshore, the FPSO operator, required for vessel class certification. The loss of production resulting from these shut-down periods is factored into the Group's 2021 production guidance. CNR and Tullow are working together with BW Offshore on the optimum remediation plan, with work expected to commence in 2022. A further update will be provided in due course once remediation plans are finalised.

Decommissioning

Decommissioning activities continue in the UK and Mauritania. In Tullow-operated licences in the UK, final surveys are being planned to close out the decommissioning programme this year. The Group's non-operated decommissioning activities are ongoing and are expected to continue through to 2025.

In Mauritania, preparation is under way to commence the Group's operated decommissioning programme of the Banda and Tiof fields with operations now expected to commence in early 2022, subject to Government approval. Non-operated decommissioning of the Chinguetti field is ongoing. The full abandonment of the wells was completed in August ahead of preparing to clear infrastructure from the seabed in 2022.

Due to a delayed start in some of the activities in Mauritania and the UK, decommissioning expenditure in 2021 is now expected to be c. $90 million (down from c.$100 million).

Kenya

Over the past year, Tullow and its Joint Venture (JV) Partners (Africa Oil and Total Energies) have completed the redesign of the Kenya development project (Blocks 10BB and 13T licences) to ensure it is a technically, commercially and environmentally robust project. A higher production plateau of 120,000 bopd is now planned, with expected gross oil recovery of 585 mmbo over the full life of the field. This resource position is supported by external international auditors Gaffney Cline Associates (GCA) who have issued a Competent Persons Report (CPR) and confirmed the life of field resource position of 585 mmbo.

The key changes to the development concept have been driven by:

1. Incorporating the production data from the Early Oil Pilot Scheme (EOPS) where 450,000 bbls was produced from Amosing and Ngamia fields. These two fields account for over 50% of the resource distribution, leading to greater confidence in achieving the higher end of the resource distribution range.
2. Optimising the number of wells to be drilled with drilling initially at the crest of the fields to achieve First Oil. Changing the producer to injector ratio from 2:1 to 1:1 leading to improved pressure support and higher resources recovered from the reservoir.
3. Adding the Ekales field into the first phase of production. Ekales is geographically straddled between the Twiga and Amosing fields and ongoing technical work has helped mature our understanding. As such, the first phase will now include the Ngamia, Ekales, Amosing and Twiga (NEAT) fields and will target 390 mmbo of the overall 585 mmbo.
4. Optimising the overall development cost with a facility design capacity of 130,000 bopd and an increase to the pipeline size from 18" to 20" to handle the increased flow rates.

Total gross capital expenditure (capex), which covers both the upstream and the pipeline to First Oil, is expected to be c.$3.4 billion. The increase in capex from the previous design is due to a bigger facility processing capacity, additional wells to be drilled and larger diameter crude oil export pipeline, which delivers 30% increase in resources whilst lowering the unit cost to $22/bbl (previously c.$31/bbl). The revised concept also allows greater flexibility in adding additional fields into production without significant modifications to the project's infrastructure.

Tullow and its JV Partners have taken the opportunity of this review to improve the environmental and social aspects of the project. Carbon emissions will be limited through a combination of heat conservation, use of associated gas for power and reinjection of excess gas into the reservoir. Further, there are opportunities to use the Kenyan national grid that is substantially powered by renewables and options to offset remaining emissions. As per the previous development plan, the 825-kilometres long pipeline that will transport the crude oil from Turkana to the port of Lamu will be heated and buried to avoid long-term disruption. The project will also require water for reservoir pressure which will be abstracted through a pipeline from the Turkwell Dam and will also be used to provide water to local communities. This project would also be Kenya's first oil and gas development and would represent a stable, long-term source of income for the Government of Kenya.

Simultaneously to the development, an exploration and appraisal plan will be put in place to ensure the remaining five discoveries are efficiently developed. This will extend and sustain initial plateau rates while keeping costs low by using the rigs used for development drilling. Future phases will also focus on additional exploration potential within the Blocks 10BB and 13T licences and also exploring the wider Blocks 10BA and 12B licence acreage.

Tullow and its JV Partners have submitted a draft FDP to the Ministry of Energy & Petroleum for their review. The JV Partners are now working collaboratively with them and will incorporate their feedback and plan to submit a final FDP by the end of 2021, in line with licence extension requirements provided by the Government of Kenya in December 2020. At the same time Tullow and its JV Partners are actively seeking strategic partners for the project. Based on the revised plan, Tullow believes that this project is an attractive commercial prospect for investors looking to access the East Africa oil and gas sector in both the upstream and midstream. It is intended that a strategic partner will be secured ahead of a Final Investment Decision.

Exploration

In Tullow's core area of West Africa, the exploration team is focused on maturing near-field and infrastructure-led exploration opportunities around existing producing fields, to unlock additional value from the Group's asset base. Tullow also continues to focus on unlocking value from the substantial prospective resource base in the emerging basins of Guyana and Argentina, while seeking to mitigate capital exposure from historical work commitments of c.$50 million in 2022, through farm-downs. These include the Beebei-Potaro exploration well on the Kanuku Block in Guyana which will target the prolific Cretaceous light oil play of the Guyana-Suriname Basin, as well as a seismic acquisition over Block MLO 122 in Argentina.

Operational activity in the first half of 2021 included the drilling of the Goliathberg-Voltzberg North well in Suriname Block 47, which encountered minor oil shows. Tullow is considering next steps for Blocks 47 and 54. The Group has notified the Government of Suriname of its decision to relinquish Block 62, and Tullow will exit the licence in October 2021. In Argentina, a multi-client 3D seismic acquisition was completed on Tullow-operated licences MLO114 and MLO119 during the first quarter of 2021. In Côte d'Ivoire seismic activities have now been fully demobilised from onshore block CI-520 and Tullow has now exited the licence. Tullow has now exited all onshore blocks in Côte d'Ivoire but retains its 90% interest in the offshore Block CI-524, adjacent to the TEN field. The Group continues to optimise its portfolio and has exited Blocks Z38 and Z64 in Peru and PEL 0037 in Namibia. Refer to note 11 for details of the Group exploration write-off assessment.

FINANCE REVIEW

Financial summary	1H 2021	1H 2020
Working interest production volume (boepd)	61,230	77,700
Sales volume (boepd)	65,800	77,100
Realised oil price ($/bbl)	60.8	51.8
Total revenue ($m)	727	731
Gross profit ($m)	321	164
Underlying cash operating costs per boe ($/boe) [1]	12.9	11.0
Exploration costs written off ($m)	49	941
Impairment of property, plant and equipment, net ($m)	8	418
Operating profit/(loss) ($m)	370	(1,306)
Profit/ (loss) before tax ($m)	213	(1,436)
Profit/(loss) after tax ($m)	93	(1,327)
Basic earnings/(loss) per share (cents)	6.5	(94.2)
Capital investment ($m) [1]	101	192
Last 12 months adjusted EBITDAX ($m) [1]	885	1,013
Net debt ($m) [1]	2,290	3,019
Gearing (times) [1]	2.6	3.0
Free cash flow ($m) [1]	86	(213)
Underlying operating cash flow ($m) [1]	218	154
Pre- Financing free cash flow ($m) [1]	227	(105)

[1] Underlying cash operating costs per boe, capital investment, adjusted EBITDAX, net debt, gearing, free cash flow, underlying operating cash flow and pre-financing free cash flow are alternative performance measures and are explained and reconciled on pages 36 to 39.

Production and commodity prices

Total Group working interest production averaged 61,230 boepd (1H 2020: 77,700 boepd), a decrease of 21% for the period. The decrease in production primarily resulted from the natural decline in Jubilee and TEN and the sale of Equatorial Guinea and Dussafu asset in Gabon in 1H21. The drilling of new wells in Ghana to offset the production decline commenced in 1H21. However, the first well drilled and completed, J-56, came onstream in July 2021 and as such did not contribute to 1H21 production.

The realised oil price after hedging for the period was $60.8/bbl (1H 2020: $51.8/bbl) and before hedging $65.2/bbl (1H 2020: $42.5/bbl). There has been a recovery in oil markets in 2H20 and 1H21, which has led to higher realised prices partially offset by hedge losses, decreasing total revenue by $52.4 million (1H 2020: increase of $130.8 million).

	1H 2021	1H 2020
Profit and Loss		
Revenue ($m)	727	731
Overlift expense ($m)	(90)	(129)
Balance Sheet		
Underlift ($m)	4	36
Overlift ($m)	(78)	(13)

The overlift expense was primarily caused by the timing of liftings with seven cargos across Ghana, Gabon and Cote d'Ivoire lifted in June 2021.

Operating costs, depreciation and expenses

Underlying cash operating costs amounted to $143 million; $12.9/boe (1H 2020: $155 million; $11.0/boe). The increase in cash unit operating costs is principally due to lower production and increased costs associated with COVID-19 operating procedures, partially offset by reduced operating costs mainly associated with Jubilee and the cessation of shuttle tanker operations in the Jubilee field in 1Q21 following commissioning of a Catenary Anchor Leg Mooring buoy. Cash operating costs excluding COVID-19 operating procedures and shuttle tanker operations were $11.6/boe (1H 2020: $9.6/boe). The sale of Equatorial Guinea and the Dussafu asset in Gabon in 1H21 also contributed to the decrease in total operating costs.

DD&A charges before impairment on production and development assets amounted to $170 million; $15.3/boe (1H 2020: $267 million; $18.9/boe). This decrease in DD&A per barrel is mainly attributable to 2020 impairments and increases to 2020 year end reserves partially offset by decreased production.

Administrative expenses of $23 million (1H 2020: $51 million) significantly decreased against the comparative period. In February 2020, Tullow concluded its Business Review, which included a review of the Group's organisation structure and resources and resulted in a significant headcount reduction. Furthermore, the Group has focused on reducing non-payroll G&A costs including outsourcing, information systems expenses, professional fees and office rent. However, this is partially offset by the adverse GBP:USD FX variance in 2021. Tullow is still on target to deliver sustainable cash savings of over $125 million per annum.

Impairment of property, plant and equipment (PP&E)	**1H 2021**	**1H 2020**
Pre-tax impairment of PP&E, net ($m)	8	418
Associated deferred tax credit ($m)	(4)	(107)
Post-tax impairment of PP&E, net ($m)	4	311

The Group recognised a net impairment charge on PP&E of $8 million in respect of first half 2021 (1H 2020: $418 million) due to changes to estimates on the cost of decommissioning for certain UK assets.

Exploration costs written off	**1H 2021**	**1H 2020**
Exploration cost written off ($m)	49	941

During the first half of 2021, the Group has written off exploration costs of $49 million (1H 2020: $941 million) which are predominantly driven by write-offs of the GVN-1 well costs in Block 47 in Suriname and subsequently all associated licence costs for all blocks in Suriname. The remaining write-offs comprise of licence level costs associated with Peru, Comoros, Côte d'Ivoire and Namibia due to no planned activity and licence exits. This is offset by a release of an indirect tax provision following settlement in Uganda relating to its disposal in 2020.

Disposals

On 9 February 2021, Tullow announced that it signed two separate sale and purchase agreements with Panoro Energy ASA for all of Tullow's assets in Equatorial Guinea and the Dussafu Marin permit asset in Gabon for a total consideration of $180 million, inclusive of contingent payments.

In March 2021, the Group completed the sale of its assets in Equatorial Guinea and $89 million was received in cash following completion adjustments. The net gain on disposal on this transaction is $123 million.

In June 2021, the Group completed the sale of its Dussafu Marin permit asset in Gabon and $39 million was received in cash following completion adjustments. An additional $5 million was received for completion of both transactions. The net gain on disposal on this transaction is $5 million.

Derivative financial instruments

Tullow continues to undertake hedging activities as part of the ongoing management of its business risk 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 30 June 2021, Tullow's hedge portfolio provides downside protection for 51% of forecast production entitlements through to May 2023 and 29% for a further 12 months to May 2024. Since completion of the comprehensive debt refinancing in May, new hedges have been placed with $55/bbl floors and weighted average sold calls of c.$70/bbl.

At 30 June 2021, the Group's derivative instruments had a net negative fair value of $148 million (30 June 2020: positive $197 million).

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. 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.

All of the Group's derivatives are Level 2 (1H 2020: Level 2). There were no transfers between fair value levels during the year.

2H 2021 hedge position at 30 June 2021	**Bopd**	**Bought put (floor)**	**Sold call**	**Bought call**
Collars	39,000	$48.12	$66.47	-
Three-way collars (call spread)	1,000	$50.00	$72.80	$82.80
Total/weighted average	40,000	$48.17	$66.63	$82.80

The 2022, 2023 and 2024 hedging position at 30 June 2021 was c.23,400 bopd, c.20,000 bopd and c.6,800 bopd hedged with an average protected floor price of $48/bbl, $55/bbl and $55/bbl respectively.

Net financing costs

Net financing costs for the period were $157 million (1H 2020: $131 million). The increase in financing costs during the period is mainly driven by finance fees, such as legal and advisor fees related to the assessment of alternative refinancing options of the extinguished RBL Facility directly expensed to the income statement ($18 million), as well as increased average cost of debt following completion of the refinancing transactions in May 2021, offset by the net gain on early settlement and derecognition of the RBL Facility and the 2022 Notes ($8 million credit).

Net financing costs include interest incurred on the Group's debt facilities, foreign exchange gains/losses, the unwinding of discount on decommissioning provisions, and the net financing costs associated with lease assets. These costs are offset by interest earned on cash deposits. A reconciliation of net financing costs is included in Note 8.

Taxation

The overall net tax expense of $120 million (1H 2020: credit of $109 million) primarily relates to expenses in respect of Ghana and West Africa non-operated assets net of non-recurring deferred tax credits associated with exploration write-offs, impairments and onerous lease provisions. The tax charge has been calculated by applying the effective tax rate which is expected to apply to each jurisdiction for the year ending 31 December 2021.

The Group's statutory effective tax rate is 56.4% (1H 2020: 7.6%). After adjusting for the non-recurring amounts related to exploration write-offs, impairments, restructuring costs, disposals and onerous lease provisions and their associated tax benefit, the Group's underlying effective tax rate is 83.1% (1H 2020: (57.7%)). The change in effective tax rate from 1H20 to 1H21 is due primarily to there being no UK tax benefit from net interest and hedging expenses in 1H21, compared to net profits in 1H20. Non-deductible expenditure in Ghana and a change to the mix of taxable and non-taxable profits in Gabon are additional contributing factors.

Analysis of effective tax rate ($'m)	**Profit/(loss) before tax**	**Tax (expense)/credit**	**Effective tax rate**
Ghana – 1H 2021	200.3	(72.6)	36.2%
1H 2020	*(65.5)*	*19.7*	*30.1%*
Gabon – 1H 2021	79.1	(38.1)	48.2%
1H 2020	*8.6*	*(11.1)*	*128.0%*
Equatorial Guinea – 1H 2021	15.5	(5.4)	35.0%
1H 2020	*15.0*	*(5.3)*	*35.6%*
Corporate – 1H 2021	(157.9)	(0.6)	-0.4%
1H 2020	*38.1*	*(9.5)*	*24.9%*
Other non-operated & exploration – 1H 2021	4.6	(0.9)	20.4%
1H 2020	*(6.3)*	*0.3*	*5.1%*
Total – 1H 2021	141.7	(117.7)	83.1%
1H 2020	*(10.1)*	*(5.8)*	*(57.7%)*

Profit/ (Loss) after tax from continuing activities and earnings /(loss) per share

The profit after tax for the period amounted to $93 million (1H 2020: $1,327 million loss). Basic earnings per share was 6.5 cents (1H 2020: basic loss per share of 94.2 cents).

Reconciliation of net debt	$m
Year-end 2020 net debt	**2,375.6**
Sales revenue	(726.8)
Operating costs	143.3
Other operating and administrative expenses	137.0
Cash flow from operations	**(446.5)**
Movement in working capital	151.1
Tax paid	37.3
Purchases of intangible exploration and evaluation assets and property, plant and equipment	97.2
Other investing activities	(134.1)
Other financing activities	213.0
Foreign exchange loss on cash	(3.6)
1H 2021 net debt	**2,290.0**

Capital investment

Capital expenditure amounted to $101 million (1H 2020: $192 million) with $65 million invested in production and development activities and $36 million invested in exploration and appraisal activities.

Capital investment will continue to be carefully controlled in the second half of 2021 and total 2021 capital expenditure is expected to be c.$260 million. The capital investment total is expected to comprise Ghana capex of c.$160 million, West African non-operated capex of c.$46 million and Kenya pre-development expenditure of c.$4 million and exploration and appraisal expenditure of c.$50 million. This reflects the reduction in capex following the sales of the Equatorial Guinea assets and the Dussafu Marin permit in Gabon, offset in part by the acceleration of the Simba expansion development in Gabon and incremental increases across Ghana, Gabon and Kenya.

Going concern

The Directors consider the going concern assessment period to be up to 30 September 2022. 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: $60/bbl for 2021, $60/bbl for 2022; and
Low Case: $45/bbl for 2021, $45/bbl for 2022.

The Low Case includes, amongst other downside assumptions, a 6 per cent production decrease compared to the Base Case as well as increased outflows associated with an ongoing dispute.

On 17 May 2021, the Group announced the completion of its offering of $1.8 billion Senior Secured Notes due 2026. The net proceeds, together with cash on balance sheet, have been used to (i) repay all amounts outstanding under, and cancel all commitments made available pursuant to, the Company's RBL Facility, (ii) redeem in full the Company's senior notes due 2022, (iii) at maturity, repay in full and cancel the Company's convertible bonds due 2021 and (iv) pay fees and expenses incurred in connection with the transactions. The Group also entered into a $500 million Super Senior Revolving Credit Facility (SSRCF) which is undrawn and will be primarily used for working capital purposes. The 2026 Senior Notes and the SSRCF do not have any maintenance covenants (disclosure of key covenants and the determination of availability under the SSRCF are provided in note 18). Following completion of these transactions the Directors have concluded that the material uncertainties noted in the 2020 Annual Report and Accounts, associated with implementing a Refinancing Proposal and obtaining amendments or waivers in respect of covenant breaches or, in the event a Refinancing Proposal is implemented, the revised covenants are subsequently breached, no longer exist.

The Group had $0.7 billion liquidity headroom of unutilised debt capacity and free cash as at 30 June 2021. The Group's forecasts show that the Group 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. These forecasts show full availability of the $500 million SSRCF, which under the Base Case remains undrawn. Furthermore Management have performed a reverse stress test and the average oil price throughout the going concern period required to reduce headroom to zero during the assessment period is $42/bbl. Based on the analysis above, the Directors have a reasonable expectation that the 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 the half year results.

2021 principal risks and uncertainties

The Board determines the key risks for the Group and monitors mitigation plans and performance on a monthly basis. An exercise was performed in June 2021 to assess whether the principal risks and uncertainties disclosed in the 2020 Annual Report continue to be appropriate given the change in external risk landscape. Although there has been some change to sub-risks, the principal risks and uncertainties facing the Group at half year remain unchanged from those disclosed in the 2020 Annual Report as listed below. Whilst the Group has successfully refinanced its debt facilities in 1H 2021 it still believes that the sustainability of its capital structure may be a risk in the medium to long term. The company risk profile continues to be assessed on an ongoing basis including considering if the pandemic or oil price volatility results in any new risks or changes to existing risks. Risks associated with COVID-19 have been considered and managed across all principal risk categories.

1. Risk of failure to deliver operations, development and subsurface objectives
2. Risk of failure to deliver commercially attractive and timely development projects
3. Risk of disruption to business due to inability to manage stakeholder relations
4. Risk of failure to manage impact of climate change
5. Risk of asset integrity breach or major production failure
6. Risk of insufficient liquidity and funding capacity
7. Risk that we fail to deliver a sustainable capital structure
8. Risk that the transformation plan fails to support the strategy and deliver cost savings
9. Risk that the people strategy and culture do not support the strategy
10. Risk of major compliance breach
11. Risk of major cyber attack

Events since 30 June 2021

There have not been any adjusting events since 30 June 2021 that have resulted in a material impact on the half year results.

Non-Adjusting event

On 17 May 2021, as part of the refinancing transaction $310 million was agreed to be put into a trustee account for settlement of principal and accrued interest of the convertible loan notes on due date. On 12 July 2021, the convertible loan notes were settled by the trustees by utilising the amount kept in the trust account.

Responsibility statement

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';
b. the interim management report includes a fair review of the information required by DTR 4.2.7R (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 (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

14 September 2021

Les Wood

Chief Financial Officer

14 September 2021

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.

Independent review report to Tullow Oil plc

Conclusion

We have been engaged by the Tullow Oil Plc (the Company) to review the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2021 which comprises of Condensed consolidated income statement, Condensed consolidated statement of comprehensive income and expense, Condensed consolidated balance sheet, Condensed statement of changes in equity, Condensed consolidated cash flow statement and the related notes 1 to 23. We have read the other information contained in the half yearly financial report and considered whether it contains any apparent misstatements or material inconsistencies with the information in the condensed set of financial statements.

Based on our review, nothing has come to our attention that causes us to believe that the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2021 is not prepared, in all material respects, in accordance with UK adopted International Accounting Standard 34 and the Disclosure Guidance and Transparency Rules of the United Kingdom's Financial Conduct Authority.

Basis for Conclusion

We conducted our review in accordance with International Standard on Review Engagements 2410 (UK and Ireland) "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the Auditing Practices Board. A review of interim financial information consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with International Standards on Auditing (UK) and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

As disclosed in note 2, the annual financial statements of the Group will be prepared in accordance with UK adopted IFRSs. The condensed set of financial statements included in this half-yearly financial report has been prepared in accordance with UK adopted International Accounting Standard 34, "Interim Financial Reporting.

Responsibilities of the directors

The Directors are responsible for preparing the half-yearly financial report in accordance with the Disclosure Guidance and Transparency Rules of the United Kingdom's Financial Conduct Authority

Auditor's Responsibilities for the review of the financial information

In reviewing the half yearly report, we are responsible for expressing to the Company a conclusion on the condensed set of financial statement in the half-yearly financial report. Our conclusion, is based on procedures that are less extensive than audit procedures, as described in the Basis for Conclusion paragraph of this report.

Use of our report

This report is made solely to the company in accordance with guidance contained in International Standard on Review Engagements 2410 (UK and Ireland) "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the Auditing Practices Board. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company, for our work, for this report, or for the conclusions we have formed.

Ernst & Young LLP
London
14 September 2021

Condensed consolidated income statement

Six months ended 30 June 2021

	Notes	Six months ended 30.06.21 Unaudited $m	Six months ended 30.06.20 Unaudited $m	Year ended 31.12.20 Audited $m
Continuing activities				
Revenue	6	726.8	731.0	1,396.1
Cost of sales	7	(405.7)	(567.0)	(993.6)
Gross profit		**321.1**	**164.0**	**402.5**
Administrative expenses	7	(23.1)	(51.5)	(86.7)
Restructuring costs and provision for onerous contracts	7	5.9	(58.6)	(92.8)
Gain/ (loss) on disposal	10	122.9	(0.1)	(3.4)
Exploration costs written off	11	(49.3)	(941.4)	(986.7)
Impairment of property, plant and equipment, net	12	(8.0)	(418.3)	(250.6)
Operating profit/ (loss)		**369.5**	**(1,305.9)**	**(1,017.7)**
Gain/ (loss) on hedging instruments		0.2	1.3	(0.8)
Finance revenue	8	22.1	29.0	59.4
Finance costs	8	(178.7)	(159.9)	(314.3)
Profit/ (loss) from continuing activities before tax		**213.1**	**(1,435.5)**	**(1,273.4)**
Income tax (expense)/ credit	9	(120.4)	108.7	51.9
Profit/ (loss) for the year from continuing activities		**92.7**	**(1,326.8)**	**(1,221.5)**
Attributable to				
Owners of the Company		92.7	(1,326.8)	(1,221.5)
Earnings/ (loss) per ordinary share from continuing activities		**¢**	**¢**	**¢**
Basic	3	6.5	(94.2)	(86.6)
Diluted	3	6.2	(94.2)	(86.6)

Condensed consolidated statement of comprehensive income and expense

Six months ended 30 June 2021

	Six months ended 30.06.21 Unaudited $m	Six months ended 30.06.20 Unaudited $m	Year ended 31.12.20 Audited $m
Profit/ (loss) for the period	92.7	(1,326.8)	(1,221.5)
Items that may be reclassified to the income statement in subsequent periods			
Cash flow hedges			
(Loss)/ gain arising in the period	(101.2)	370.6	271.0
Losses arising in the period – time value	(108.2)	(31.9)	(37.3)
Reclassification adjustments for items included in loss/ (profit) on realisation	30.8	(155.7)	(268.1)
Reclassification adjustments for items included in loss on realisation – time value	21.6	24.8	49.4
Exchange differences on translation of foreign operations	(2.0)	(1.8)	(5.3)
Other comprehensive (expense)/ income	(159.0)	206.0	9.8
Tax relating to components of other comprehensive expense	2.8	(15.5)	(2.7)
Net other comprehensive (expense)/ income for the period	(156.2)	190.5	7.1
Total comprehensive expense for the period	**(63.5)**	**(1,136.3)**	**(1,214.4)**
Attributable to			
Owners of the Company	(63.5)	(1,136.3)	(1,214.4)

Condensed consolidated balance sheet

As at 30 June 2021

	Notes	Six months ended 30.06.21 Unaudited $m	Six months ended 30.06.20 Restated Unaudited $m	Year ended 31.12.20 Audited $m
Assets				
Non-current asset				
Intangible exploration and evaluation assets	11	346.3	356.6	368.2
Property, plant and equipment	12	3,144.1	3,326.0	3,237.9
Other non-current assets	14	514.9	577.5	547.4
Derivative financial instruments		6.6	43.9	2.6
Deferred tax assets		490.4	495.5	494.3
		4,502.3	4,799.5	4,650.4
Current assets				
Inventories		141.3	121.8	96.1
Trade receivables	13	256.4	64.5	79.0
Other current assets	14	1,044.0	745.7	717.1
Current tax assets		41.4	58.5	36.4
Derivative financial instruments		–	153.0	17.2
Cash and cash equivalents		301.8	236.3	805.4
Assets classified as held for sale		–	610.8	155.6
		1,784.9	1,990.6	1,906.8
Total assets		6,287.2	6,790.1	6,557.2
Liabilities				
Current liabilities				
Trade and other payables	17	(887.6)	(831.6)	(750.7)
Borrowings	18	(297.8)	–	(3,170.5)
Provisions	19	(255.3)	(161.8)	(229.8)
Current tax liabilities		(95.1)	(98.5)	(52.2)
Derivative financial instruments		(104.5)	–	(17.8)
Liabilities directly associated with assets classified as held for sale		–	(28.8)	(187.3)
		(1,640.3)	(1,120.7)	(4,408.3)
Non-current liabilities				
Trade and other payables	17	(1,013.3)	(1,147.7)	(1,064.7)
Borrowings	18	(2,565.5)	(3,239.2)	–
Provisions	19	(575.5)	(774.2)	(620.9)
Deferred tax liabilities		(709.4)	(646.5)	(673.3)
Derivative financial instruments		(50.2)	–	–
		(4,913.9)	(5,807.6)	(2,358.9)
Total liabilities		(6,554.2)	(6,928.3)	(6,767.2)
Net liabilities		(267.0)	(138.2)	(210.0)
Equity				
Called up share capital		213.8	211.2	211.7
Share premium		1,294.7	1,294.7	1,294.7
Equity component of convertible bonds		48.4	48.4	48.4
Foreign currency translation reserve		(249.4)	(243.9)	(247.4)
Hedge reserve		(62.6)	203.9	4.8
Hedge reserve – time value		(92.1)	(24.6)	(5.4)
Merger reserve		755.2	755.2	755.2
Retained earnings		(2,175.0)	(2,383.1)	(2,272.0)
Equity attributable to equity holders of the Company		(267.0)	(138.2)	(210.0)
Total equity		(267.0)	(138.2)	(210.0)

Condensed statement of changes in equity

As at 30 June 2021

	Share capital $m	Share premium $m	Equity component of convertible bonds $m	Foreign currency translation reserve[1] $m	Hedge reserve[2] $m	Hedge reserve – Time value $m	Merger reserve $m	Retained earnings $m	Total equity $m
At 1 January 2020 (previously reported)	210.9	1,380.0	48.4	(242.1)	4.6	(17.5)	755.2	(1,155.9)	983.6
Restatement[3]	–	(85.3)	–	–	–	–	–	85.3	–
At 1 January 2020 (as adjusted)	210.9	1,294.7	48.4	(242.1)	4.6	(17.5)	755.2	(1,070.6)	983.6
Loss for the period	–	–	–	–	–	–	–	(1,326.8)	(1,326.8)
Hedges, net of tax	–	–	–	–	199.3	(7.1)	–	–	192.2
Currency translation adjustments	–	–	–	(1.8)	–	–	–	–	(1.8)
Exercising of employee share options	0.3	–	–	–	–	–	–	(0.3)	–
Share-based payment charges	–	–	–	–	–	–	–	14.6	14.6
At 30 June 2020 (as adjusted)	211.2	1,294.7	48.4	(243.9)	203.9	(24.6)	755.2	(2,383.1)	(138.2)
Profit for the period	–	–	–	–	–	–	–	105.3	105.3
Hedges, net of tax	–	–	–	–	(199.1)	19.2	–	–	(179.9)
Currency translation adjustments	–	–	–	(3.5)	–	–	–	–	(3.5)
Exercising of employee share options	0.5	–	–	–	–	–	–	(0.5)	–
Share-based payment charges	–	–	–	–	–	–	–	6.3	6.3
At 1 January 2021	211.7	1,294.7	48.4	(247.4)	4.8	(5.4)	755.2	(2,272.0)	(210.0)
Profit for the period	–	–	–	–	–	–	–	92.7	92.7
Hedges, net of tax	–	–	–	–	(67.4)	(86.7)	–	–	(154.1)
Currency translation adjustments	–	–	–	(2.0)	–	–	–	–	(2.0)
Exercising of employee share options	2.1	–	–	–	–	–	–	(2.1)	–
Share-based payment charges	–	–	–	–	–	–	–	6.4	6.4
At 30 June 2021	213.8	1,294.7	48.4	(249.4)	(62.6)	(92.1)	755.2	(2,175.0)	(267.0)

[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, and exchange gains or losses arising on long-term foreign currency borrowings which are a hedge against the Group's overseas investments.

[2] The hedge reserve represents gains and losses on derivatives classified as effective cash flow hedges.

[3] Comparative information in respect of share premium and retained earnings at 1 January 2020, 30 June 2020 and for the 6 months ended 30 June 2020 have been restated in relation to the treatment of the exercise of nil-cost employee share options which are issued at nominal value rather than market value as previously recognised. This has an $85.3 million impact on the opening position as at 1 January 2020 and $85.9 million as at 30 June 2020 and $0.6 million impact on the options issued in 1H 2020. This restatement was included in the 2020 Annual Report and Accounts.

Condensed consolidated cash flow statement

Six months ended 30 June 2021

	Notes	Six months ended 30.06.21 Unaudited $m	Six months ended 30.06.20 Unaudited $m	Year ended 31.12.20 Audited $m
Cash flows from operating activities				
Profit/ (loss) from continuing activities before tax		213.1	(1,435.5)	(1,273.4)
Adjustments for				
Depreciation, depletion and amortisation		178.7	277.6	467.1
(Gain)/ loss on disposal	10	(122.9)	0.1	3.4
Exploration costs written off	11	49.3	941.4	986.7
Impairment of property, plant and equipment, net	12	8.0	418.3	250.6
Restructuring costs and provision for onerous contracts	19	(5.9)	58.6	92.8
Payments under restructuring costs and provision for onerous contracts	19	(8.9)	(36.1)	(58.4)
Decommissioning expenditure		(27.7)	(37.8)	(57.7)
Share-based payment charge		6.4	12.0	20.9
(Gain)/ loss on hedging instruments		(0.2)	(1.3)	0.8
Finance revenue	8	(22.1)	(29.0)	(59.4)
Finance costs	8	178.7	159.9	314.3
Operating cash flow before working capital movements		446.5	328.2	687.7
(Increase)/ decrease in trade and other receivables		(143.2)	147.1	195.2
(Increase)/ decrease in inventories		(50.2)	66.4	85.1
Increase/ (decrease) in trade payables		42.3	(246.0)	(161.9)
Cash flows from operating activities		295.4	295.7	806.1
Income taxes paid		(37.3)	(93.1)	(107.5)
Net cash from operating activities		258.1	202.6	698.6
Cash flows from investing activities				
Proceeds from disposals, net of cash disposed	10	132.4	0.5	513.4
Purchase of intangible exploration and evaluation assets		(55.8)	(101.2)	(213.6)
Purchase of property, plant and equipment		(41.4)	(121.0)	(217.3)
Interest received		1.7	0.7	1.8
Net cash from/ (used) in investing activities		36.9	(221.0)	84.3
Cash flows from financing activities				
Debt arrangement fees		(57.8)	–	–
Repayment of borrowings	23	(2,080.0)	(110.0)	(185.0)
Payment into trust for repayment of convertible bond[1]		(309.8)	–	–
Drawdown of borrowings	23	1,800.0	270.0	270.0
Repayment of obligations under leases		(68.3)	(86.3)	(158.2)
Finance costs paid		(86.9)	(105.0)	(198.5)
Net cash used in financing activities		(802.8)	(31.3)	(271.7)
Net (decrease)/ increase in cash and cash equivalents		(507.8)	(49.7)	511.2
Cash and cash equivalents at beginning of period		805.4	288.8	288.8
Foreign exchange gain/(loss)		4.2	(2.8)	5.4
Cash and cash equivalents at end of period	15	301.8	236.3	805.4

[1] On 17 May 2021, as part of the refinancing transaction $309.8 million was agreed to be put into a trustee account for settlement of principal and accrued interest of the convertible loan notes on due date. On 12 July 2021 the convertible loan notes were settled by the trustees by utilising the amount kept in the trust account. This this has been disclosed as a financing activity within cash flow statement.

Notes to the condensed financial statements

Six months ended 30 June 2021

1. General information

The condensed financial statements for the six-month period ended 30 June 2021 have been prepared in accordance with UK adopted International Accounting Standard (IAS) 34 Interim Financial Reporting and the requirements of the Disclosure and Transparency Rules (DTR) of the Financial Conduct Authority (FCA) in the United Kingdom as applicable to interim financial reporting.

The Condensed financial statements represent a 'condensed set of financial statements' as referred to in the DTR issued by the FCA. Accordingly, they do not include all the information required for a full annual financial report and are to be read in conjunction with the Group's financial statements for the year ended 31 December 2020, which were prepared in accordance with international accounting standards in conformity with the requirements of the Companies Act 2006 and International Financial Reporting Standards (IFRS) adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the European Union (EU). The Condensed financial statements are unaudited and do not constitute statutory accounts as defined in section 434 of the Companies Act 2006. The financial information for the year ended 31 December 2020 does not constitute statutory accounts as defined in section 434 of the Companies Act 2006. This information was derived from the statutory accounts for the year ended 31 December 2020, a copy of which has been delivered to the Registrar of Companies. The auditor's report on these accounts was unqualified, drew attention by way of emphasis of matter to the material uncertainty related to going concern without qualifying the accounts and did not contain a statement under sections 498 (2) or (3) of the Companies Act 2006.

2. Accounting policies

The annual financial statements of Tullow Oil plc will be prepared in accordance with United Kingdom adopted international accounting standards ("UK adopted IFRSs"). The condensed set of financial statements included in this half-yearly financial report has been prepared in accordance with UK adopted International Accounting Standard 34 'Interim Financial Reporting', and the Disclosure and Transparency Rules of the Financial Services Authority.

There were adjustments made in relation to a recognition of additional JV receivables ($23.4 million) and reclassification between accruals ($37.9 million) and provisions ($46 million) that should have been accounted in the prior period and was not done so in error. In the directors' judgement, these amounts were not considered material based on their nature as working capital reclassifications and in assessment against the relative impact of the financial statement line items, so the prior period amounts have not been corrected.

The accounting policies adopted in the 2021 half-yearly financial report are the same as those adopted in the 2020 Annual report and accounts.

Going Concern

The Directors consider the going concern assessment period to be up to 30 September 2022. 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: $60/bbl for 2021, $60/bbl for 2022; and
Low Case: $45/bbl for 2021, $45/bbl for 2022.

The Low Case includes, amongst other downside assumptions, a 6 per cent production decrease compared to the Base Case as well as increased outflows associated with an ongoing dispute.

On 17 May 2021, the Group announced the completion of its offering of $1.8 billion Senior Secured Notes due 2026. The net proceeds, together with cash on balance sheet, have been used to (i) repay all amounts outstanding under, and cancel all commitments made available pursuant to, the Company's RBL Facility, (ii) redeem in full the Company's senior notes due 2022, (iii) at maturity, repay in full and cancel the Company's convertible bonds due 2021 and (iv) pay fees and expenses incurred in connection with the transactions. The Group also entered into a $500 million Super Senior Revolving Credit Facility (SSRCF) which is undrawn and will be primarily used for working capital purposes. The 2026 Senior Notes and the SSRCF do not have any maintenance covenants (disclosure of key covenants and the determination of availability under the SSRCF are provided in note 18). Following completion of these transactions the Directors have concluded that the material uncertainties noted in the 2020 Annual Report and Accounts, associated with implementing a Refinancing Proposal and obtaining amendments or waivers in respect of covenant breaches or, in the event a Refinancing Proposal is implemented, the revised covenants are subsequently breached, no longer exist.

The Group had $0.7 billion liquidity headroom of unutilised debt capacity and free cash as at 30 June 2021. The Group's forecasts show that the Group 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. These forecasts show full availability of the $500 million SSRCF, which under the Base Case remains undrawn. Furthermore Management have performed a reverse stress test and the average oil price throughout the going concern period required to reduce headroom to zero during the assessment period is $42/bbl. Based on the

3. Accounting policies continued

analysis above, the Directors have a reasonable expectation that the 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 the half year results.

4. Earnings/ (loss) per ordinary share

The calculation of basic earnings/ (loss) per share is based on the profit/ (loss) for the period after taxation attributable to equity holders of the parent of $92.7 million (1H 2020: loss of $1,326.8 million) and a weighted average number of shares in issue of 1,421.3 million (1H 2020: 1,408.9 million).

The calculation of diluted earnings per share is based on the profit for the period after taxation as for basic earnings per share. The number of shares outstanding, however, is adjusted to show the potential dilution if employee share options are converted into ordinary shares. The weighted average number of ordinary shares is increased by 67.5 million resulting in a diluted weighted average number of shares of 1,488.8 million.

5. Dividends

The Directors intend to recommend that no 2021 interim dividend be paid.

6. Approval of accounts

These unaudited half year results were approved by the Board of Directors on 14 September 2021.

7. 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, profit and certain asset and liability information regarding the Group's reportable business segments for the period ended 30 June 2021, 30 June 2020 and 31 December 2020.

	Ghana $m	Non-Operated $m	Kenya $m	Exploration $m	Corporate $m	Total $m
Six months ended 30 June 2021						
Sales revenue by origin	467.8	259.0	–	–	–	726.8
Segment result[1]	237.1	94.8	0.8	(63.3)	(5.6)	263.8
Gain on disposal						122.9
Unallocated corporate expenses[2]						(17.2)
Operating profit						369.5
Gain on hedging instruments						0.2
Finance revenue						22.1
Finance costs						(178.7)
Profit before tax						213.1
Income tax expense						(120.4)
Profit after tax						92.7
Total assets	4,927.0	539.4	289.4	147.9	383.5	6,287.2
Total liabilities[3]	(2,862.4)	(483.0)	(25.9)	(44.5)	(3,138.4)	(6,554.2)
Other segment information						
Capital expenditure:						
Property, plant and equipment	95.7	9.7	–	0.3	0.7	106.4
Intangible exploration and evaluation assets	0.8	(13.9)	4.4	36.1	–	27.4
Depletion, depreciation and amortisation	(155.7)	(15.3)	(0.7)	–	(7.0)	(178.7)
Impairment of property, plant and equipment, net	–	(8.0)	–	–	–	(8.0)
Exploration costs written off	(0.9)	14.1	0.8	(63.3)	–	(49.3)

[1] Segment result is a non-IFRS measure which includes gross profit, exploration costs written off and impairment of property, plant and equipment. See reconciliation below.

[2] Unallocated expenditure include amounts of a corporate nature and not specifically attributable to a segment.

[3] Total liabilities - Corporate comprise of the Group's external debt and other non-attributable liabilities.

6. Segmental reporting continued

Reconciliation of segment result

	Six months ended 30.06.21 Unaudited $m	Six months ended 30.06.20 Unaudited $m	Year ended 31.12.20 Audited $m
Segment result	263.8	(1,195.7)	(834.8)
Add back			
Exploration costs written off	49.3	941.4	986.7
Impairment of Property, Plant and Equipment	8.0	418.3	250.6
Gross profit	321.1	164.0	402.5

6. Segmental reporting continued

	Ghana $m	Non-Operated $m	Kenya $m	Exploration $m	Corporate $m	Total $m
Six months ended 30 June 2020						
Sales revenue by origin	480.1	250.9	–	–	–	731.0
Segment result	(293.1)	(368.6)	(429.2)	(93.2)	(11.6)	(1,195.7)
Loss on disposal						(0.1)
Unallocated corporate expenses						(110.1)
Operating loss						(1,305.9)
Gain on hedging instruments						1.3
Finance revenue						29.0
Finance costs						(159.9)
Loss before tax						(1,435.5)
Income tax credit						108.7
Loss after tax						(1,326.8)
Total assets	4,898.5	1,190.2	295.4	170.6	235.4	6,790.1
Total liabilities	(2,780.5)	(683.8)	(45.8)	(67.6)	(3,350.6)	(6,928.3)
Other segment information						
Capital expenditure:						
Property, plant and equipment	77.8	80.2	0.2	0.2	3.7	162.1
Intangible exploration and evaluation assets	0.4	35.6	9.0	69.6	–	114.6
Depletion, depreciation and amortisation	(234.5)	(34.4)	(0.7)	–	(8.0)	(277.6)
Impairment of property, plant and equipment, net	(305.8)	(112.5)	–	–	–	(418.3)
Exploration costs written off	(0.5)	(418.0)	(429.2)	(93.7)	–	(941.4)
Year ended 31 December 2020						
Sales revenue by origin	963.5	432.6	–	–	–	1,396.1
Segment result	124.9	(410.2)	(430.0)	(104.3)	(15.2)	(834.8)
Loss on disposal						(3.4)
Unallocated corporate expenses						(179.5)
Operating loss						(1,017.7)
Loss on hedging instruments						(0.8)
Finance revenue						59.4
Finance costs						(314.3)
Loss before tax						(1,273.4)
Income tax credit						51.9
Loss after tax						(1,221.5)
Total assets	4,859.3	656.3	300.5	181.8	559.3	6,557.2
Total liabilities	(2,696.7)	(688.4)	(34.1)	(44.2)	(3,303.8)	(6,767.2)
Other segment information						
Capital expenditure:						
Property, plant and equipment	94.6	127.1	0.6	0.2	7.2	229.7
Intangible exploration and evaluation assets	0.9	68.5	9.5	91.8	–	170.7
Depletion, depreciation and amortization	(390.1)	(60.7)	(1.5)	–	(14.8)	(467.1)
Impairment of property, plant and equipment	(149.1)	(100.5)	–	(0.4)	(0.6)	(250.6)
Exploration costs written off	(0.8)	(452.0)	(430.0)	(103.9)	–	(986.7)

6. Segmental reporting continued

	Sales revenue six months ended 30.06.21 $m	Sales revenue six months ended 30.06.20 $m	Sales revenue Year ended 31.12.20 $m	*Non-current assets 30.06.21 $m	*Non-current assets 30.06.20 $m	*Non-current assets 31.12.20 $m
Ghana	467.8	480.2	963.5	3,477.5	3,603.6	3,584.6
Total Ghana	**467.8**	**480.2**	**963.5**	**3,477.5**	**3,603.6**	3,584.6
Kenya	–	–	–	256.3	256.9	251.8
Total Kenya	**–**	**–**	**–**	**256.3**	**256.9**	**251.8**
Argentina	–	–	–	29.2	15.6	21.2
Cote d'Ivoire	–	–	–	–	4.5	2.7
Guyana	–	–	–	64.9	57.7	61.4
Suriname	–	–	–	–	31.4	35.6
Peru	–	–	–	–	0.1	0.3
Exploration other	–	–	–	–	0.5	–
Total Exploration	**–**	**–**	**–**	**94.1**	**109.8**	**121.2**
Gabon	178.0	140.5	274.5	61.5	104.1	68.8
Côte d'Ivoire	25.9	34.6	41.3	75.4	60.9	81.5
Equatorial Guinea[1]	55.1	75.6	116.8	–	79.7	–
Other	–	0.1	–	–	–	–
Total Non- Operated	**259.0**	**250.8**	**432.6**	**136.9**	**244.7**	**150.3**
Corporate	–	–	–	40.5	45.0	45.6
Total	**726.8**	**731.0**	**1,396.1**	**4,005.3**	**4,260.1**	**4,153.5**

*Excludes derivative financial instruments and deferred tax assets.

[1] $76.0 million of non-current assets was transferred to Assets Held for Sale in December 2020. The disposal of Equatorial Guinea was completed in March 2021. Refer to note 10.

7. Operating profit

	Six months ended 30.06.21 Unaudited $m	Six months ended 30.06.20 Unaudited $m	Year ended 31.12.20 Audited $m
Operating profit is stated after charging:			
Operating costs	143.3	155.3	331.7
Depletion and amortisation of oil and gas and leased assets[1]	169.5	266.7	446.4
Underlift, overlift and oil stock movement[2]	89.5	128.9	160.5
Share-based payment charge included in cost of sales	0.4	1.3	0.9
Other cost of sales	3.0	14.8	54.1
Total cost of sales	405.7	567.0	993.6
Administrative expenses			
Share-based payment charge included in administrative expenses	6.0	10.7	20.0
Depreciation of other property, plant and equipment[1]	9.2	10.9	20.7
Other administrative costs	7.9	29.9	46.0
Total administrative expenses	23.1	51.5	86.7
Total restructuring costs and provision for onerous contracts	(5.9)	58.6	92.8

[1] Depreciation expense on leased assets of $26.0 million as per note 12 includes a charge of $1.9 million on leased administrative assets, which is presented within administrative expenses in the income statement. The remaining balance of $24.1 million relates to other leased assets and is included within cost of sales.

[2] Refer to Note 17 for detailed explanation.

8. Net financing costs

	Six months ended 30.06.21 Unaudited $m	Six months ended 30.06.20 Unaudited $m	Year ended 31.12.20 Audited $m
Interest on bank overdrafts and borrowings	113.0	106.8	205.8
Interest on obligations for leases	43.1	46.1	91.0
Total borrowing costs	156.1	152.9	296.8
Finance fees	18.7	0.5	0.8
Other Interest expense	0.2	–	3.6
Unwinding of discount on decommissioning provisions	3.7	6.5	13.1
Total finance costs	178.7	159.9	314.3
Interest income on amounts due from joint venture partners for leases	(19.8)	(28.6)	(40.6)
Other finance revenue	(2.3)	(0.4)	(18.8)
Total finance revenue	(22.1)	(29.0)	(59.4)
Net financing costs	156.6	130.9	254.9

9. Taxation on profit/ (loss) on ordinary activities

The overall net tax expense of $120.4 million (1H 2020: credit of $108.7 million) primarily relates to expenses in respect of Ghana and West Africa non-operated assets net of non-recurring deferred tax credits associated with exploration write-offs, impairments and onerous lease provisions. The tax charge has been calculated by applying the effective tax rate which is expected to apply to each jurisdiction for the year ending 31 December 2021.

The Group's statutory effective tax rate is 56.4% (1H 2020: 7.6%). After adjusting for the non-recurring amounts related to exploration write-offs, impairments, restructuring costs, disposals and onerous lease provisions and their associated tax benefit, the Group's underlying effective tax rate is 83.1% (1H 2020: (57.7%)). The change in effective tax rate from 1H20 to 1H21 is due primarily to there being no UK tax benefit from net interest and hedging expenses in 1H21, compared to net profits in 1H20. Non-deductible expenditure in Ghana and a change to the mix of taxable and non-taxable profits in Gabon are additional contributing factors.

Uncertain tax positions

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 other 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 with significant updates described in more detail below. 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.

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 unprovided liabilities of $1,084.6 million (YE20: $1,070.2 million) which includes $34.1 million of interest and penalties (YE20: $61.2m).

Provisions of $90.4 million (YE20: $129.3 million) are included in income tax payable ($34.8 million (YE20: $30.4m)), provisions ($55.5 million (YE20: $52.4m)) and accruals (nil (YE20: $46.4m)). Where these matters relate to expenditure which is capitalised within E&A and PP&E, 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.

The provisions and unprovided tax liabilities relating to these disputes have increased following new claims being initiated and extrapolation of exposures, but have decreased following the conclusion of tax authority challenges and matters lapsing under statutes of limitation, giving rise to an overall decrease in provision of $38.9m and increase in unprovided tax liabilities of $14.4m.

Ghana tax assessments

In August 2018, Tullow Ghana Limited ("TGL") received an assessment from the Ghana Revenue Authority ("GRA") for the financial years 2014 to 2016. After discussions, a final assessment was issued in December 2019 for $407.3 million requesting that $397.7 million be paid by 13 January 2020. The GRA is seeking to apply branch profits remittance tax under a law which the Group considers is not applicable to TGL, since it falls outside the tax regime set out in TGL's petroleum agreement and double tax treaties. The GRA has additionally assessed TGL for unpaid withholding taxes and corporate income tax arising from the disallowance of loan interest. The Group considers that these assessments also breach TGL's rights under its petroleum agreements, applicable Ghanaian law and double taxation treaties, and, in some cases, have arisen as the result of the errors in the GRA's calculations. In January 2020, TGL issued a Notice of Dispute with the Ministry of Energy ("MoE"), disputing the issues and suspending TGL's obligation to pay any taxes until the disputed issues have been resolved. In April 2020, the GRA issued a Demand Notice for $365.0 million ($337.6 million branch profits remittance tax and withholding tax, and $27.4 million corporate income tax) which was put on hold by the MoE. In September 2021 TGL received a revised final tax audit report for $471.2 million ($325 million branch profits remittance tax and withholding tax, and $146.1 million corporate income tax). The Group continues to dispute the validity of these assessments and is evaluating what steps may be required in addition to the existing dispute process.

Kenya tax assessments

In March 2019, Tullow Kenya BV ("TKBV") received an assessment from the Kenya Revenue Authority ("KRA") for $11.7 million for VAT on the Block 12A farm-down. The Group considered that VAT was not applicable since TKBV was not VAT registered at the time of the disposal and the transaction was in relation to the sale of a capital asset or part of a business. The KRA sought to apply VAT on the basis that the transaction was a disposal of trading stock and therefore the exemption to register for VAT did not apply. This matter has now been heard by the Tax Appeals Tribunal and TKBV received a judgment on 30 April 2021 in its favour which set aside the VAT assessment in its entirety. However, the KRA appealed to the High Court the decision of the TAT, but they withdrew that appeal on 19 July 2021 and this was confirmed at a mention before the court on 18 August 2021. This matter can now be treated as closed.

9. Taxation on profit/ (loss) on ordinary activities continued

Uganda Joint Venture Partner tax assessments

TOTAL E&P Uganda B.V. and CNOOC Uganda Limited have reached a settlement with the Uganda Revenue Authority on all existing and potential tax litigation and/or assessments for the period up to June 2015 for PAYE, VAT and WHT, resulting in a reduction in unprovided liabilities of $22.0 million.

Timing of cash-flows

While it is not possible to estimate the timing of tax cash flows in relation to possible outcomes with certainty. Management anticipate that there will not be material cash taxes paid in excess of the amounts provided for uncertain tax positions in the next 12 months.

10. Disposals

Equatorial Guinea and Dussafu asset in Gabon

On 31 March 2021, the Group completed the sale of its assets in Equatorial Guinea with a cash consideration received of $88.9 million. This transaction included contingent future payments of up to $16.0 million which are linked to asset performance and oil price. A further $5.0 million of additional consideration was also received on completion of Dussafu Marin permit asset in Gabon.

On 9 June 2021, the Group completed the sale of Dussafu asset sale in Gabon with a cash consideration received of $39.0 million. This transaction included contingent future payments of up to $24.0 million which are linked to asset performance and oil price.

The asset performance and oil price conditions required for receipt of contingent future payments are not expected to be met and accordingly no contingent consideration has been recognised as at 30 June 2021.

Book value of assets disposed	**Equatorial Guinea Six months ended 30.06.21 Unaudited $m**	**Dussafu Six months ended 30.06.21 Unaudited $m**	**Total Six months ended 30.06.21 Unaudited $m**
Property, plant and equipment	72.9	52.0	124.9
Inventories	6.9	3.2	10.1
Other current assets	68.5	1.7	70.1
Total assets disposed	148.3	56.9	205.1
Trade and other payables	(36.0)	(18.5)	(54.5)
Provisions	(118.2)	(4.7)	(122.9)
Current tax liabilities	(13.6)	–	(13.6)
Deferred tax liabilities	(17.9)	–	(17.8)
Total liabilities disposed	(185.7)	(23.2)	(208.8)
Net (liabilities)/ assets disposed	(37.4)	33.7	(3.7)
Cash consideration	93.8	39.0	132.8
Transaction costs	(8.4)	(0.3)	(8.7)
Gain on disposal[1]	122.8	5.0	127.8

[1] In addition to $127.8 million gain on disposal recognised following the Equatorial Guinea and Dussafu disposals, the Group recognised a loss of $5.0 million relating to its sale of Dutch assets to Hague and London Oil plc (HALO) in 2017, and a gain of $0.1 million relating to other transactions during the period (1H21: 122.9 million; 1H20: 0.1 million).

Uganda

During 2020, the Group completed the disposal of its interest in Uganda for upfront cash consideration of $500.0 million, with $75.0 million due on FID and contingent future payments linked to oil prices. On completion, $514.3 million was received in cash, representing the upfront consideration plus $14.3 million of completion adjustments. The $75.0 million payment due on FID has been recorded as a current receivable and is expected to be received in 2H21. After deducting transaction costs paid in 2020, net cash proceeds on disposal was $513.4 million.

10. Disposals continued

Book value of assets disposed	Uganda 31.12.2020 Audited $m
Intangible exploration and evaluation assets	580.4
Trade receivables	0.3
Other current assets	2.8
Total assets disposed	583.5
Trade and other payables	(0.9)
Net assets disposed	582.6

11. Intangible exploration and evaluation assets

	Six months ended 30.06.21 Unaudited $m	Six months ended 30.06.20 Unaudited $m	Year ended 31.12.20 Audited $m
At 1 January	368.2	1,764.4	1,764.4
Additions	27.4	108.2	170.7
Amounts written off	(49.3)	(941.4)	(986.7)
Transfer from Property, Plant and Equipment	–	3.8	–
Net transfer to assets held for sale	–	(578.5)	(580.4)
Currency translation adjustments	–	0.1	0.2
At 30 June/31 December	346.3	356.6	368.2

Exploration costs written off	Rationale for write-off six months ended 30.06.21	Write-off 30.06.21 Unaudited $m	Remaining recoverable amount 30.06.21 Unaudited $m
Suriname	b,c	56.9	–
Uganda	d	(15.3)	–
Gabon	c	1.7	–
Peru	b	1.0	–
Cote d'Ivoire	b	4.2	–
Other	a,c	0.8	–
Exploration costs written off		49.3	–

a. Current year expenditure on assets previously written off
b. Licence relinquishments, expiry, planned exit or reduced activity
c. Unsuccessful well costs written off
d. Release of indirect tax provision following settlement

11.Intangible exploration and evaluation assets continued

In the prior year, the Group received a licence extension in Kenya to 31 December 2021. In order to obtain a further license extension, the Group is required to submit a technically and commercially compliant Field Development Plan (FDP) to the Government of Kenya by 31 December 2021. In addition, the Group is looking for strategic partners to help finance the development of the project.

Following the redesign of the Kenya development project during 2021, the underlying value of the project has increased. However, the uncertainty in form of risks around licence extension and ability to bring in strategic partners to help finance the project has also increased. As such, the Group has prepared a probabilistic assessment to assess whether an adjustment to the carrying value of Kenya exploration asset is required. Based on the result of this probabilistic assessment, the Group considers no adjustment to the carrying value is required as at 30 June 2021. Refer to page 5 of Operational Review for further detail.

Exploration costs written off	Rationale for write-off six months ended 30.06.20	Write-off 30.06.20 Unaudited $m	Remaining recoverable amount 30.06.20 Unaudited $m
Kenya	e	429.2	240.3
Uganda	f	417.5	–
Peru	d	40.1	–
Comoros	b	11.3	–
Cote d'Ivoire	b	9.2	–
Guyana	a	6.9	–
Other	a,c	27.2	–
Exploration costs written off		941.4	240.3

a. Current year expenditure on assets previously written off
b. Licence relinquishments, expiry, planned exit or reduced activity
c. Pre-licence exploration expenditure is written off as incurred
d. Unsuccessful well costs written off
e. Following VIU assessment as a result of reduction in long term oil price assumption, using a pre-tax discount rate of 18%
f. Written down to the value of the transaction consideration.

Exploration costs written off	Rationale for write-off year ended 31.12.20	Write-off 31.12.20 Audited $m	Remaining recoverable amount 31.12.20 Audited $m
Kenya	e	430.0	247.0
Uganda	f	451.4	–
Peru	b,d	41.2	–
Comoros	b	12.4	–
Cote d'Ivoire	b	14.3	–
Guyana	a	9.2	42.2
Other	a,c	28.2	–
Exploration costs written off		986.7	289.2

a. Current year expenditure on assets previously written off
b. Licence relinquishments, expiry, planned exit or reduced activity
c. Pre-licence exploration expenditure is written off as incurred
d. Unsuccessful well costs written off
e. Following VIU assessment as a result of reduction in long term oil price assumption, using a pre-tax discount rate of 18%
f. Written down to the value of the transaction consideration.

12. Property, plant and equipment

	Oil and gas assets six months ended 30.06.21 Unaudited $m	Right of use assets six months ended 30.06.21 Unaudited $m	Other property, plant and equipment six months ended 30.06.21 Unaudited $m	Total six months ended 30.06.21 Unaudited $m	Oil and gas assets six months ended 30.06.20 Unaudited $m	Right of use assets six months ended 30.06.20 Unaudited $m	Other property, plant and equipment six months ended Restated[1] 30.06.20 Unaudited $m	Total six months ended Restated[1] 30.06.20 Unaudited $m	Oil and gas assets Year ended 31.12.20 Audited $m	Right of use assets Year ended 31.12.20 Audited $m	Other property, plant and equipment six months ended 31.12.20 Audited $m	Total Year ended 31.12.20 Audited $m
Cost												
At 1 January	10,460.2	1,018.6	69.6	11,548.4	11,279.6	1,038.5	190.6	12,508.7	11,279.6	1,038.5	190.6	12,508.7
Additions	45.4	59.8	1.2	106.4	137.8	19.5	4.8	162.1	203.6	16.5	9.6	229.7
Disposals	–	–	(0.8)	(0.8)	–	(7.6)	(0.4)	(8.0)	(11.0)	(17.6)	(125.6)	(154.2)
Transfer to intangible E&E assets	–	–	–	–	(3.8)	–	–	(3.8)	–	–	–	–
Transfer from/(to) assets held for sale	–	–	–	–	–	–	–	–	(1,050.9)	(19.5)	–	(1,070.4)
Currency translation adjustments	15.4	0.4	0.5	16.3	(72.8)	(2.5)	(12.4)	(87.7)	38.9	0.7	(5.0)	34.6
At 30 June/31 December	10,521.0	1,078.8	70.5	11,670.3	11,340.8	1,047.9	182.6	12,571.3	10,460.2	1,018.6	69.6	11,548.4
Depreciation, depletion and amortization and impairment												
At 1 January	(7,915.9)	(352.3)	(42.3)	(8,310.5)	(8,194.6)	(264.7)	(157.7)	(8,617.0)	(8,194.6)	(264.7)	(157.7)	(8,617.0)
Charge for the year	(145.4)	(26.0)	(7.3)	(178.7)	(228.8)	(41.3)	(7.5)	(277.6)	(382.3)	(72.4)	(12.4)	(467.1)
Impairment loss	(8.0)	–	–	(8.0)	(418.3)	–	–	(418.3)	(250.0)	–	(0.6)	(250.6)
Capitalised depreciation	–	(14.2)	–	(14.2)	–	(13.2)	–	(13.2)	–	(23.8)	–	(23.8)
Disposal	–	–	0.8	0.8	–	1.2	0.3	1.5	10.9	7.1	122.8	140.8
Transfer to assets held for sale	–	–	–	-	–	–	–	–	938.2	1.6	–	939.8
Currency translation adjustments	(15.4)	–	(0.2)	(15.6)	68.1	0.4	10.8	79.3	(38.1)	(0.1)	5.6	(32.6)
At 30 June/31 December	(8,084.7)	(392.5)	(49.0)	(8,526.2)	(8,773.6)	(317.6)	(154.1)	(9,245.3)	(7,915.9)	(352.2)	(42.3)	(8,310.5)
Net book value at 30 June/31 December	2,436.3	686.3	21.5	3,144.1	2,567.2	730.3	28.5	3,326.0	2,544.3	666.3	27.3	3,237.9

[1] Other property, plant and equipment as at 30 June 2020 have been restated to include a derecognition of an asset that was fully impaired during the year ended 31 December 2019. The impact reflected in both cost and accumulated depreciation was $108.1 million on the opening balance as at 1 January 2020, $106.7 million on disposals and $1.4 million on currency transaction adjustments during the period ended 30 June 2020. This restatement was included in the 2020 Annual Reports and Accounts.

12. Property, plant and equipment continued

	Trigger for impairment/ (reversal) six months ended 30.06.21	Impairment/ (reversal) 30.06.21 (unaudited) $m	30.06.21 Remaining recoverable amount (unaudited) $m
Limande and Turnix CGU (Gabon)	a	(0.5)	6.7
UK 'CGU'	a, b	8.5	–
Impairment		8.0	6.7

a. Change to decommissioning estimate
b. The fields in the UK are grouped into one CGU as all fields share critical gas infrastructure

	Trigger for impairment six months ended 30.06.20	Impairment 30.06.20 (unaudited) $m	Pre tax discount rate assumption	30.06.20 Remaining recoverable amount (unaudited) $m
Limande and Turnix CGU (Gabon)	a	26.7	13%	4.9
Ezanga (Gabon)	a	18.1	15%	2.6
Oba and Middle Oba CGU (Gabon)	a	3.6	15%	9.3
Ruche (Gabon)	a,b	23.4	13%	35.6
Espoir (Cote d'Ivoire)	a	12.8	10%	60.7
TEN (Ghana)	a	305.8	10%	1,427.8
Mauritania	c	16.9	n/a	–
UK 'CGU'	c, d	11.0	n/a	–
Impairment		418.3		1,540.9

a. Decrease to short, medium and long-term oil price assumptions
b. Recognition of FPSO lease
c. Change to decommissioning estimate
d. The fields in the UK are grouped into one CGU as all fields share critical gas infrastructure

	Trigger for impairment/ (reversal) year ended 31.12.20	Impairment/ (reversal) 31.12.20 (audited) $m	Pre tax discount rate assumption	31.12.20 Remaining recoverable amount (audited) $m
Limande and Turnix CGU (Gabon)	a	28.0	13%	7.4
Ezanga (Gabon)	a	20.5	15%	1.8
Oba and Middle Oba CGU (Gabon)	a	3.8	15%	8.7
Ruche (Gabon)	a,b	1.2	13%	32.4
Espoir (Cote d'Ivoire)	a	(2.1)	10%	81.5
TEN (Ghana)	a	149.2	10%	1,510.6
Mauritania	c	30.6	n/a	–
UK 'CGU'	c,d	13.2	n/a	–
Other	c,e	6.2	n/a	–
Impairment		250.6		

a. Decrease to short, medium and long-term oil price assumptions
b. Recognition of FPSO lease
c. Change to decommissioning estimate
d. Revision of value based on revision to reserves
d. The fields in the UK are grouped into one CGU as all fields share critical gas infrastructure

12. Property, plant and equipment continued

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
1H20	$40/bbl*	$45/bbl*	$50/bbl	$55/bbl	$60/bbl	$60/bbl inflated by 2%
FY 2020	$45/bbl	$50/bbl	$55/bbl	$60/bbl	$60/bbl	$60/bbl inflated by 2%

*Forward curve as at 30 June

13. Trade receivables

Trade receivables comprise amounts due for the sale of oil and gas. They are generally due for settlement within 30-60 days and are therefore all classified as current. The Group holds the trade receivable with the objective of collecting the contractual cash flows and therefore measures them subsequently at amortised cost using the effective interest method.

The balance of trade receivables as of 31 June 2021 is $256.4 million (1H 2020: $64.5 million; FY20: $79.0 million). The increase as at 30 June 2021 compared to 31 December 2020 and 30 June 2020 of $177.4 million and $191.9 million, respectively, is mainly due to increased oil prices as well as additional Jubilee (Ghana) and Oguendjo (Gabon) liftings in June 2021 which were settled in July 2021.

14. Other assets

	30.06.21 Unaudited $m	30.06.20 Unaudited $m	31.12.20 Audited $m
Non-current			
Amounts due from joint venture partners[1]	514.9	577.1	547.4
Other non-current assets	–	0.4	–
	514.9	577.5	547.4
Current			
Amounts due from joint venture partners[1]	572.9	593.0	521.9
Underlift	3.8	35.9	19.5
Prepayments	57.8	64.1	60.7
Other current assets[2]	395.9	52.7	115.0
	1,030.4	745.7	717.1

[1] The decrease in non-current receivables from JV Partners compared to June 2020 and December 2020 mainly relate to reduction in time remaining on the TEN FPSO lease, net decrease in GNPC ("Ghana National Petroleum Corporation") receivable partially offset increases associated with new lease liabilities. The movement in current receivables from JV Partners relates mainly to timing of partner balances partially offset by a recognition of the JV receivable associated with the recognition of the Maersk Venturer offshore drilling rig as a lease liability (see note 16).

[2] Other current assets mainly include funds paid into trust to settle principal plus interest of the Convertible Bond at maturity in July 2021 ($309.8 million) (note 17), the deferred consideration relating to the Uganda disposal ($75.0 million) (note 10) as well as the deferred consideration relating to the Netherlands disposal in 2017 ($3.3 million) and VAT recoverable ($15.0 million).

15. Cash and cash equivalents

	30.06.21 Unaudited $m	30.06.20 Unaudited $m	31.12.20 Audited $m
Cash at bank	138.0	117.9	224.2
Short- term deposits and other cash equivalents[1]	163.8	118.4	581.2
	301.8	236.3	805.4

[1] As at 31 December 2020, short-term deposits and other cash equivalents mainly relates to receipt of cash for the disposal of Uganda of $514.3 million which were used for the repayment of borrowings in 2021. Refer to note 23.

Cash and cash equivalents include an amount of $72.0 million (1H 2020: $32.0 million); FY20: $54.0 million)) which the Group holds as operator in JV bank accounts. Included within cash at bank is $67.4 million (1H 2020: $67.0 million; FY20: $77.1 million) held in JV bank accounts as the Group's share of security for the letters of credit issued in relation to decommissioning activities.

16. Assets and liabilities classified as held for sale

On 9 February 2021, the Group announced that it had signed two separate sale and purchase agreements with Panoro Energy ASA of its entire interest in Equatorial Guinea and its entire interest in the Dussafu Marin permit in Gabon, in each case with an effective date of 1 July 2020. Both transactions completed in 1H21. Refer to note 10.

On 23 April 2020, Tullow announced that it had signed a Sale and Purchase Agreement with Total Uganda with an effective date of 1 January 2020, in which it agreed to transfer its entire interests in Blocks 1, 1A, 2 and 3A in Uganda and the proposed East African Crude Oil Pipeline (EACOP) System to Total. The transaction completed in 2H20.

17. Trade and other payables

	30.06.21 Unaudited $m	30.06.20 Unaudited $m	31.12.20 Audited $m
Non-current			
Other non-current liabilities	81.2	84.4	89.0
Non-current portion of leases	932.1	1,063.4	975.7
	1,013.3	1,147.8	1,064.7
Current			
Trade payables	53.4	85.8	38.3
Other payables[1]	56.7	89.3	49.5
Overlift	77.7	13.4	3.8
Accruals	388.0	370.7	409.4
VAT and other similar taxes	–	8.9	8.9
Current portion of leases	311.8	263.5	240.8
	887.6	831.6	750.7

[1] Other payables include accrued interest of $50.5 million (FY20: $40.9 million)

Trade and other payables are non-interest bearing except for leases.

Payables related to operated joint ventures (primarily related to Ghana and Kenya) are recorded gross with the debit representing the partners' share recognised in amounts due from joint venture partners (note 13). The change in trade payables and in other payables predominantly represents timing differences and levels of work activity.

Overlifts of $77.7 million as at 30 June 2021 is attributable to TEN ($29.3 million), Jubilee ($23.0 million) and Gabon ($25.4 million). This is an increase of $74.9 million and $64.3 million from December 2020 and June 2020. This was caused by the timing of liftings with seven cargos across Ghana, Gabon and Cote d'Ivoire lifted in June 2021.

On 2 April 2021 the Group contracted Maersk Venturer offshore drilling rig to undertake the drilling work programme for Jubilee and TEN fields in Ghana. As at 30 June 2021, Tullow carries a right of use assets of $43.0 million (see note 12), and gross lease liability of $97.3 million as Tullow entered the lease on behalf of the JV. A receivable from JV Partners of $53.5 million has been recognised in other assets to reflect the value of future payments that will be met by cash calls from JV Partners (see note 14). The lease has been recognised for an 18-month term, in line with the early termination option included in the contract and approvals received by the JV Partners.

18. Borrowings

	30.06.21 Unaudited $m	30.06.20 Unaudited $m	31.12.20 Audited $m
Current			
Borrowings – within one year			
6.625% Convertible Bonds due 2021 ($300 million)	297.8	–	290.9
6.25% Senior Notes due 2022 ($650 million)	–	–	646.7
7.00% Senior Notes due 2025 ($800 million)	–	–	791.2
Reserves Based Lending credit facility	–	–	1,441.7
Carrying value of total current borrowings	297.8	–	3,170.5
Non-current			
Borrowings – after one year but within five years			
6.625% Convertible Bonds due 2021 ($300 million)	–	284.5	–
6.25% Senior Notes due 2022 ($650 million)	–	646.1	–
7.00% Senior Notes due 2025 ($800 million)	791.6	790.8	–
10.25% Senior Notes due 2026 ($1800 million)	1,773.9	–	–
Reserves Based Lending credit facility	–	1,517.8	–
Carrying value of total non-current borrowings	2,565.5	3,239.2	–
Carrying value of total borrowings	2,863.3	3,239.2	3,170.5

On 17 May 2021, the Group completed a comprehensive refinancing of its debt with the issuance of a five-year $1.8 billion Senior Secured Notes (“2026 Notes”) and a new $500 million Super Senior Revolving Credit Facility (SSRCF) which will primarily be used for working capital purposes.

The 2026 Notes have been used to (i) repay all amounts outstanding under, and cancel all commitments made available pursuant to, the Company’s Reserves Based Lending Facility, (ii) redeem in full the Company’s Senior Notes due 2022, (iii) at maturity, on 12 July 2021, repay in full and cancel the Company’s convertible bonds due 2021 and (iv) pay fees and expenses incurred in connection with the transactions.

The 2026 Notes, maturing in May 2026, require an annual prepayment of $100 million of the outstanding principal amount plus accrued and unpaid interest.

The SSRCF, maturing in December 2024, comprises of (i) a $500 million revolving credit facility and (ii) a $100 million letter of credit facility.

The 2026 Notes and the SSRCF will be senior secured obligations of Tullow Oil Plc and will be guaranteed by certain of the Group's subsidiaries.

As at 31 December 2020, the Group has assessed it does not have an unconditional right to defer payment of the facility, Senior Notes due 2022, or Senior Notes due 2025 based on a forecast breach in covenants; as such, these borrowings were classified as current. Following the refinancing in May 2021, the Senior Notes due 2025 have been classified as non-current in line with their contractual maturity.

Capital management

The Group defines capital as the total equity and net debt of the Group. Capital is managed in order to provide returns for shareholders and benefits to stakeholders and to safeguard the Group’s ability to continue as a going concern. Tullow is not subject to any externally imposed capital requirements. To maintain or adjust the capital structure, the Group may put in place new debt facilities, issue new shares for cash, repay debt, engage in active portfolio management, adjust the dividend payment to shareholders, or undertake other such restructuring activities as appropriate. No significant changes were made to the capital management objectives, policies or processes during the half year ended 30 June 2021. The Group monitors capital on the basis of the gearing, being net debt divided by adjusted EBITDAX, and maintains a policy target of between 1x and 2x.

SSRCF covenants

The SSRCF does not have any financial maintenance covenants. Availability under the $500m million cash tranche of the facility is determined on an annual basis with reference to the Net Present Value of the 2P reserves of the Group (2P NPV) at the end of the preceding calendar year. SSRCF debt capacity is calculated as 2P NPV divided by 1.1x less Senior Notes outstanding.

18. Borrowings continued

Senior Notes covenants

The Senior Notes are subject to customary high yield covenants including limitations on debt incurrence, asset sales and restricted payments such as dividends. The key debt incurrence covenant is the Fixed Charge Cover Ratio ("FCCR").

The FCCR is the ratio of the Consolidated Cash Flow to the Fixed Charges for the previous twelve months. The 'Consolidated Cash flow' essentially represents an Adjusted EBITDAX calculation. The Fixed Charges represent the aggregate financial charges related to the Company's indebtedness i.e. interest on all the Group's borrowings and interests under capital leases less any finance revenues. The Company may incur additional financial indebtedness if the FCCR for the Company's most recently ended two full fiscal half-years immediately preceding the date on which such additional indebtedness is incurred would have been at least 2.25 to 1.0 on a pro-forma basis. Drawdowns under the SSRCF are not subject to the FCCR covenant and are always permitted subject to the availability calculation set out above. There has been no debt incurrence event since the Senior Notes have been issued.

19. Provisions

	Decommissioning 30.06.21 Unaudited $m	Other provisions 30.06.21 Unaudited $m	Total 30.06.21 Unaudited $m	Decommissioning 30.06.20 Unaudited $m	Other provisions 30.06.20 Unaudited $m	Total 30.06.20 Unaudited $m	Decommissioning 31.12.20 Audited $m	Other provisions 31.12.20 Audited $m	Total 31.12.20 Audited $m
At 1 January	696.1	154.6	850.7	850.1	76.2	926.3	850.1	76.2	926.3
New provisions, changes in estimates and reclassifications	14.4	36.5	50.9	27.2	61.4	88.6	14.9	136.6	151.5
Changes in discount rate	(31.7)	–	(31.7)	–	–	–	–	–	–
Transfer to assets and liabilities held for sale	–	–	–	–	–	–	(129.2)	–	(129.2)
Payments	(36.6)	(8.9)	(45.5)	(37.8)	(36.1)	(73.9)	(57.7)	(58.4)	(116.1)
Unwinding of discount	3.7	–	3.7	6.5	–	6.5	13.1	–	13.1
Currency translation adjustment	2.3	0.4	2.6	(11.0)	(0.5)	(11.5)	4.9	0.2	5.1
At 30 June/31 December	648.2	182.6	830.8	835.0	101.0	936.0	696.1	154.6	850.7
Current provisions	116.9	138.4	255.3	69.1	92.7	161.8	104.4	125.4	229.8
Non-current provisions	531.3	44.2	575.5	765.9	8.3	774.2	591.7	29.2	620.9

Other provisions include non-income tax provision, restructuring provision and disputed cases and claims.
The decommissioning provision represents the present value of decommissioning costs relating to the European and African oil and gas interests.

In 2021, the Group has increased the decommissioning discount rate by 0.5% from 31 December 2020 due to a movement in the risk-free rate. This resulted in a decrease of the provision by $23.7 million in Ghana, $3.7 million in Cote d'Ivoire and $4.3 million in Gabon.

20. Called up share capital and share premium

As at 30 June 2021, the Group had in issue 1,429.0 million allotted and fully paid ordinary shares of GBP 10 pence each (30 June 2020: 1,410.9 million).

In the six months ended 30 June 2021, the Group issued 14.9 million shares in respect of employee share options (1H 2020:3.0 million new shares in respect of employee share options).

21. Contingent Liabilities

	30.06.21 Unaudited $m	30.06.20 Unaudited $m	31.12.20 Audited $m
Contingent liabilities			
Performance guarantees	102.8	111.6	115.6
Other contingent liabilities	83.6	116.5	82.9
	186.4	228.1	198.5

Performance guarantees are in respect of abandonment obligations, committed work programmes and certain financial obligations.

Other contingent liabilities

This includes amounts for ongoing legal disputes with third parties where we consider the likelihood of cash outflow to be higher than remote but not probable. The timing of any economic outflow if it were to occur would likely range between one and five years.

In January 2013, the Group acquired Spring Energy Norway AS (Spring) from HitecVision V (Hitec), a Norwegian private equity company, and Spring employee minority shareholders. In addition to the initial consideration payable under the sale and purchase agreement for Spring, the Group undertook to make contingent bonus payments to Hitec and the Spring employee minority shareholders in the event of the discovery on or before 31 December 2016 of commercially viable reserves from four identified drilling prospects (including the Wisting prospect in licence PL537).

In September 2013, OMV Norge AS, the operator of PL537, announced that it had made a discovery by drilling the Wisting prospect. Hitec claims that the conditions for a bonus payment under the Spring SPA had been met in respect of the Wisting prospect in PL537 as at December 2016. Tullow has disputed this position. An arbitration was commenced in Norway to determine if a bonus payment is payable in respect of the Wisting discovery and a decision is expected to be made in late 2021. Hitec has claimed US$95 million, including interest(which Tullow has disputed). This claim amount is based on a preliminary calculation that is subject to update.

In 2016, the Group sold its interest in PL537 to Equinor but remains responsible for this dispute.

22. Events since 30 June 2021

On 17 May 2021, as part of the refinancing transaction $309.8 million was agreed to be put into a trustee account for settlement of principal and accrued interest of the convertible loan notes on due date. On 12 July 2021 the convertible loan notes were settled by the trustees by utilizing the amount kept in the trust account. This is a non-adjusting event.

23. Cash flow statement reconciliations

Movement in borrowings	1H 21 $m	FY 20 $m	1H 20 $m	FY 19 $m	1H21 Movement	1H20 Movement	2020 Movement
Borrowings	2,863.3	3,170.5	3,239.2	3,071.7	(307.2)	167.5	98.8
Associated cash flows							
Debt arrangement fees					(57.8)	–	–
Repayment of borrowings					(2,080.0)	(110.0)	(185.0)
Drawdown of borrowings					1,800.0	270.0	270.0
Non-cash movements/presented in other cash flow lines							
Amortisation of arrangement fees and accrued interest					30.6	7.5	13.8

Commercial Reserves and Contingent Resources summary working interest basis

	Ghana		Non-Operated		Kenya		Exploration		Total		
	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Total mmboe
COMMERCIAL RESERVES[1]											
1 January 2021	180.1	179.2	48.4	11.1	–	–	–	–	228.5	190.2	260.2
Revisions	–	–	0.2	(0.1)	–	–	–	–	0.2	(0.1)	0.2
Disposals	–	–	(14.7)	–	–	–	–	–	(14.7)	–	(14.7)
Production	(7.7)	–	(3.3)	(0.7)	–	–	–	–	(11.0)	(0.7)	(11.1)
30 June 2021	172.4	179.2	30.6	10.3	–	–	–	–	203.0	189.5	234.6
CONTINGENT RESOURCES[2]											
1 January 2021	217.0	749.1	59.5	78.4	170.8	–	54.5	–	501.7	827.5	639.7
Revisions	–	–	(0.2)	0.3	60.6	–	–	–	60.4	0.3	60.4
Disposals/ Relinquishments	–	–	(30.1)	(77.5)	–	–	–	–	(30.1)	(77.5)	(43.0)
30 June 2021	217.0	749.1	29.2	1.2	231.4	–	54.5	–	532.1	750.3	657.1
TOTAL											
30 June 2021	389.4	928.3	59.8	11.5	231.4	–	54.5	–	735.1	939.8	891.7

[1] Proven and Probable Commercial Reserves are as audited and reported by an independent engineer. Reserves estimates for each field are reviewed by the independent engineer based on significant new data or a material change with a review of each field undertaken at least every two years, with the exception of minor assets contributing less than 5 per cent of the Group's reserve.

[2] Proven and Probable Contingent Resources are as audited and reported by an independent engineer. Resources estimates are reviewed by the independent engineer based on significant new data received following exploration or appraisal drilling.

The Group provides for depletion and amortisation of tangible fixed assets on a net entitlement basis, which reflects the terms of the Production Sharing Contracts related to each field. Total net entitlement reserves were 224.7 mmboe at 30 June 2021 (31 December 2020: 248.9 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 development within the foreseeable future. Kenya contingent resources have increased following a review by independent auditor, Gaffney, Cline & Associates that utilised additional data from the Early Oil Pilot Scheme. Refer to page 5 for further details.

Alternative performance measures

The Group uses certain measures of performance which 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 and free 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, additions to administrative assets and certain other adjustments. The Directors believe that capital investment is a useful indicator of the Group's organic expenditure on exploration and appraisal 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.

	1H 2021	**1H 2020**
Additions to property, plant and equipment	106.4	162.1
Additions to intangible exploration and evaluation assets	27.4	114.6
Less		
Decommissioning asset adjustments	(17.3)	27.2
Right-of-use asset additions	59.8	19.5
Lease payments related to capital activities	(8.7)	(2.2)
Capitalised share-based payment charge	–	0.6
Additions to administrative assets	1.2	4.8
Other non-cash capital expenditure	(2.4)	34.5
Capital investment	**101.2**	**192.3**
Movement in working capital	(5.2)	25.1
Additions to administrative assets	1.2	4.8
Cash capital expenditure per the cash flow statement	**97.2**	**222.2**

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 payments to convertible bond trustees and cash and cash equivalents. Non-cash adjustments include unamortised arrangement fees, adjustment to convertible bonds, and other adjustments. The Group’s definition of net debt does not include the Group’s leases as the Group’s focus is the management of cash borrowings and a lease is viewed as deferred capital investment. The value of the Group’s lease liabilities as at 30 June 2021 was $311.8 million current and $932.1 million non-current; it should be noted that these balances are recorded gross for operated assets and are therefore not representative of the Group’s net exposure under these contracts.

	1H 2021	1H 2020
Current borrowings	297.8	–
Non- current borrowings	2,565.5	3,239.2
Non-cash adjustments[1]	38.3	16.6
Payment to Convertible Bond trustees[2]	(309.8)	–
Less cash and cash equivalents[3]	(301.8)	(236.3)
Net debt	**2,290.0**	**3,019.5**

[1] Non-cash adjustments include unamortised arrangement fees which are incurred on creation or amendment of borrowing facilities as well as the Convertible Bonds which were measured at fair value. The difference between the fair value and the principal of the bond was included as a component of equity and a decrease to borrowings. Over the life of the Convertible Bond, the fair value reduces until the carrying value of the borrowings is equal to the principal outstanding for repayment on maturity.

[2] As part of the refinancing, it was agreed that Tullow would pay $300 million plus coupon of $10 million to the Convertible Bonds Paying Agent (Deutsche Bank) on 17 May 2021. This amount was held in Trust until repayment on maturity date of 12 July 2021.

[3] Cash and cash equivalents include an amount of $72 million (1H 2020: $32 million) which the Group holds as operator in JV bank accounts. Included within cash at bank is $67 million (1H 2020: $67 million) held in JV bank accounts as the Group's share of security for the letters of credit issued in relation to decommissioning activities.

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. This definition of gearing differs from the one included in the RBL facility agreements. Adjusted EBITDAX is defined as profit/(loss) from continuing activities adjusted for income tax (expense)/credit, finance costs, finance revenue, gain on hedging instruments, depreciation, depletion and amortisation, share-based payment charge, restructuring costs, gain/(loss) on disposal, exploration cost written off, impairment of property, plant and equipment net, and provision for onerous service contracts.

	1H 2021	1H 2020
Adjusted EBITDAX[1]	884.9	1,012.9
Net debt	2,290.0	3,019.5
Gearing (times)	2.6	3.0

[1] Last 12 months (LTM). Refer to the 2020 Annual Report and Accounts for a full reconciliation of Adjusted EBITDAX.

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, depletion and amortisation of oil and gas assets, underlift, overlift and oil stock movements, share-based payment charge included in cost of sales, and certain other cost of sales. Underlying cash operating costs are divided by production to determine underlying cash operating costs per boe.

	1H 2021	**1H 2020**
Cost of sales	405.7	567.0
Add		
Lease payments related to operating activity	9.2	1.2
Less		
Depletion and amortisation of oil and gas and leased assets[1]	169.5	266.7
Underlift, overlift and oil stock movements[2]	89.5	128.9
Share-based payment charge included in cost of sales[3]	0.4	1.3
Other cost of sales[4]	12.2	16.0
Underlying cash operating costs	**143.3**	**155.3**
Working Interest Production (MMboe)	11.1	14.1
Underlying cash operating costs per boe ($/boe)	**12.9**	**11.0**

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

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

[3] Share-based payment charge included in cost of sales relates to the portion of the non-cash share-based payment charge that relates to employees who work on operational projects.

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

Free cash flow

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

	1H 2021	**1H 2020**
Net cash from operating activities	258.1	202.6
Net cash from/ (used) in investing activities	36.9	(221.0)
Debt arrangement fees	(57.8)	–
Repayment of obligations under leases	(68.3)	(86.3)
Finance costs paid	(86.9)	(105.0)
Foreign exchange gain/ (loss)	4.2	(2.8)
Free cash flow	**86.2**	**(212.5)**

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 free cash flow

This is a useful indicator of the Group's assets 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.

	1H 2021	**1H 2020**
Net cash from operating activities	258.1	202.6
Less		
Decommissioning expenditure	27.7	37.8
Plus		
Repayment of obligations under leases	(68.3)	(86.3)
Underlying operating cash flow	217.5	154.1
Net cash from/(used) in investing activities	36.9	(221.0)
Decommissioning expenditure	(27.7)	(37.8)
Pre-financing free cash flow	**226.7**	**(104.7)**

EVENTS ON THE DAY

In conjunction with these results, Tullow is conducting a virtual presentation webcast.

09:00 GMT – UK/European conference call

To access the call please dial the appropriate number below shortly before the call and ask for the Tullow Oil plc conference call. The telephone numbers and access codes are:

Live event	
All participants	+44 (0) 20 7192 8338
UK freephone	0800 279 6619
Event plus passcode	1378144

WEBCAST

To join the live audio webcast or play the on-demand version, please use this link:

https://edge.media-server.com/mmc/p/d5erhti3

The replay will be available from noon on 15 September 2021.

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Notes to editors

Tullow is an independent oil and gas, exploration and production group which is quoted on the London, Irish and Ghanaian stock exchanges (symbol: TLW) and is a constituent of the FTSE250 index. The Group has interests in over 40 exploration and production licences across 11 countries including Ghana where it operates the Jubilee and TEN fields. In March 2021, Tullow committed to becoming Net Zero on its Scope 1 and 2 emissions by 2030.

For further information, please refer to our website at www.tullowoil.com.

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