2020 Full Year Results

Tullow Oil plc

10 March 2021

TULLOW OIL PLC - 2020 FULL YEAR RESULTS

10 March 2021 – Tullow Oil plc ("Tullow"), the independent oil and gas exploration and production group ("Group"), announces its Full Year Results for the year ended 31 December 2020. Details of a management presentation, webcast and conference call are available on the last page of this announcement or visit the Group's website www.tullowoil.com.

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

"After a year of significant change for Tullow, we are now executing a robust, cash generative business plan which is focused on our most productive assets. We have transformed our cost base, implemented rigorous capital discipline and are well placed to benefit from higher oil prices. We will start a multi-year, multi-well drilling programme in Ghana next month to deliver sustainable and profitable production growth. Our self-help initiatives will deliver c.$1 billion, including over $700 million from asset sales in the past year. Strong business delivery, increased liquidity and improving commodity prices support constructive refinancing discussions. Importantly, we are also announcing today that we intend to be Net Zero by 2030 as part of our commitment to sustainability. This commitment is in line with our desire to work closely with Host Communities and Governments and our investors to deliver a long-term and sustainable business."

2020 FULL YEAR RESULTS SUMMARY

- Group working interest production averaged 74,900 bopd, in line with expectations
- Revenue of $1,396 million; gross profit of $403 million; loss after tax of $1,222 million
- Loss after tax driven by non-cash exploration write-offs and impairments totalling $1,237 million pre-tax
- Underlying operating cash flow of $598 million[2] and pre-financing cash flow of $625 million[2]
- Capital and decommissioning expenditure were $288 million[2] and $58 million respectively
- Net debt at year-end of c.$2.4 billion[2]; gearing of 3.0x[2] net debt/EBITDAX; headroom and free cash of c.$1.1 billion
- Strong operational performance in Ghana; both FPSOs delivered in excess of 95% uptime during the year
- $575 million Uganda asset sale to Total completed in November 2020; $75 million contingent payment expected in 2021

LONG TERM BUSINESS PLAN[1]

- 10-year business plan presented at a Capital Markets Day on 25 November 2020 (CMD) to deliver material value and cash flow
- Business plan to generate c.$7 billion underlying operating cash flow and c.$4 billion pre-financing cash flow @ $55/bbl
- Material upside to oil price with business plan generating an additional $1.5 billion of pre-financing cash flow @ $65/bbl
- Over 90% of capital to focus on West African producing assets; options being worked to unlock value in Kenya and South America
- Cost focus is delivering annual savings of >$125 million through 53% headcount reduction, outsourcing and other efficiencies
- A strong foundation has been created to address near-term debt maturities and reduce gearing to 1-2x net debt/EBITDAX
- 2P reserves increased to 260 mmboe representing a 2020 reserves replacement ratio of c.160%, underpinning the business plan

2021 OUTLOOK[1]

- Group working interest oil production year-to-date in line with expectations; full year guidance of 60,000 – 66,000 bopd
- Underlying operating cash flow and pre-financing cash flow expected to be c.$0.5 billion and c.$0.2 billion respectively at $50/bbl
- Every $10/bbl increase in the oil price delivers c.$100 million incremental pre-financing cash flow up to $75/bbl
- Capex of c.$265 million; decommissioning of c.$100 million; Ghana drilling programme with four wells in 2021 to start in April
- Sale of interests in Equatorial Guinea and Dussafu in Gabon for up to $180 million agreed; completion expected in H1
- Suriname exploration well result expected early in Q2; focused on prospect maturation across the exploration portfolio
- In Kenya, a comprehensive review of the development concept is being completed to assess future strategic options
- The Tullow Board has committed to the Group becoming Net Zero on its Scope 1 and 2 emissions by 2030

REFINANCING UPDATE

Tullow has been reviewing its business plan and operating strategy with its creditors and their advisers. The plan is expected to generate material cash flow and create a solid foundation to address near-term debt maturities. Tullow's low-cost asset base is leveraged to oil price upside. As part of the ongoing refinancing discussions, Tullow has now received approval for a new debt capacity amount under the Reserve Based Lending facility ("RBL") of $1.7 billion. With this new debt capacity agreed, Tullow has liquidity headroom and free cash of c.$0.9 billion. The combination of strong business delivery, increased liquidity, recent asset sales and higher commodity prices is providing a positive impetus to constructive discussions with creditors. The Group is confident that a mutually satisfactory agreement on debt refinancing can be reached in the first half of this year.

[1] 2021 guidance is provided before adjusting for the effects of the Equatorial Guinea and Dussafu asset sales

[2] Alternative performance measures are reconciled on pages 26 to 29

2020 KEY FINANCIAL RESULTS

	2020	2019
Total revenue ($m)	1,396	1,683
Gross profit ($m)	403	759
Loss after tax ($m)	(1,222)	(1,694)
Free cash flow ($m)	432	355
Net debt ($m)	2,376	2,806
Gearing (times)	3.0	2.0

OPERATIONAL REVIEW

Production, Reserves and Resources

In 2020, Tullow's West Africa oil assets performed in line with expectations delivering average working interest oil production of 74,900 bopd. In 2021, working interest oil production is expected to average between 60,000 and 66,000 bopd. This forecast will be adjusted for the sales of the Equatorial Guinea and Dussafu assets once these transactions complete. As laid out at the Group's CMD, investment focused on the Group's cash generative producing assets in West Africa is expected to increase production in 2022 and sustain it for the longer term.

Tullow's audited 2P reserves have increased from 243 mmboe at the end of 2019 to 260 mmboe at the end of 2020. Based on 27 mmboe of 2020 production, this represents an organic reserves replacement ratio of c.160%, underpinning the business plan presented at the CMD. This was largely driven by a 31.5 mmboe increase at Jubilee following improved field performance and the acceleration of development projects in the new plan. Tullow's audited 2C resources decreased from 1,102 mmboe to 640 mmboe, largely resulting from the Uganda asset sale.

Group average working interest production	**FY 2020**	**FY 2021 guidance**
Ghana	52.4	40.5
Jubilee	29.5	24.3
TEN	23.0	16.2
Equatorial Guinea	4.8	4.8
Gabon	15.5	15.4
Côte d'Ivoire	2.1	2.3
Oil production	74.9	63.0

Net Zero

Tullow has committed to becoming a Net Zero Company by 2030 on its Scope 1 and 2 emissions through a combination of decarbonising its operated assets in Ghana and pursuing a nature-based carbon removal programme. Investment in decarbonisation projects over the next three years will result in an increase in the gas handling capacity on Jubilee and enable process modifications on TEN, which will also put the Group on track to eliminate routine flaring in Ghana by 2025. To offset the residual difficult-to-abate carbon emissions, work is under way to identify nature-based carbon removal projects, such as reforestation, afforestation and conservation that Tullow will invest in to achieve its Net Zero ambition by 2030. We will also seek to align our carbon offset strategy with government priorities, emerging regulation on Article 6 of the Paris Agreement as well as our Shared Prosperity strategy, focused on creating socio-economic opportunities for our host communities.

Ghana

The effects of the COVID-19 pandemic on our operations have been managed safely across the business with no impact on Ghana production. This has been achieved in close cooperation with the Government of Ghana who have enabled effective testing and quarantine measures to be put in place. However, this increased the net cost of operations by c.$10 million in 2020.

Both fields in Ghana performed in line with expectations in 2020, with the Jubilee field averaging 83,600 bopd gross (net: 29,500 bopd) and the TEN field averaging 48,700 bopd gross (net: 23,000 bopd). This production performance was supported by increased and sustained gas offtake nominations from the Government of Ghana, approval from the Ministry of Energy to increase flaring, higher than forecast facility uptime of over 95% at both FPSOs and improved well optimisation and water injection facility performance on the Jubilee FPSO.

To deliver an operational turnaround for the Ghana assets starting in 2020, key areas of focus have been asset integrity, process safety, maintenance and reliability. Gas offtake and water injection on Jubilee have been an important part of the strategy to address the decline in production in the absence of sustained drilling. The engineering work to increase redundancy and reliability has resulted in record levels of water injection with rates now in excess of 200kbwpd, despite a failure in a water injection riser in November 2020. Sustained water injection helps support reservoir pressure and improves overall sweep efficiency. Good progress has also been made on gas offtake. Onshore gas demand is stabilising, facility reliability has improved and there is greater alignment with the Government of Ghana on projected offtake. Overall this has resulted in current offtake levels of c.125 mmscfd. Gas processing and water injection capacities are both expected to be steadily enhanced through 2021 and beyond to deliver long-term stable production.

In consultation with the Ghana joint venture partners and supported by expert advisors, a comprehensive review of the investment and production optimisation plans for Jubilee and TEN was conducted in the second half of 2020. The resulting plan was presented at the CMD and demonstrated the substantial potential of the Ghana portfolio given its large resource base and extensive infrastructure in place. It showed that, managed with a rigorous focus on costs and capital discipline, these assets have the potential to generate material cash flow over the next decade and deliver significant value for Ghana and investors.

The Maersk Venturer drillship has been contracted to start a multi-well programme which is envisaged to be for a minimum period of four years. The rig has arrived in Ghanaian waters and is scheduled to commence drilling in April. The same rig worked on the previous drilling programme in Ghana, but the contract was terminated due to the oil price impacts of the COVID-19 pandemic. The drilling hiatus, along with historical underinvestment has had a negative impact on 2021 production. In 2021, the rig is expected to drill and complete four wells in total, consisting of two Jubilee production wells, one Jubilee water injector well and one TEN gas injector well to provide pressure support to two Ntomme oil production wells. This well campaign is expected to begin to offset near-term production decline and further wells in 2022 will see production materially recover and be sustained for the long term. This drilling programme incorporates lessons learned from the previous programme and is targeting a 20% reduction in drilling costs through simplified well designs, improved rig reliability and supply chain savings.

The final phase of the Jubilee Turret Remediation Project was the installation of a Catenary Anchor Leg Mooring (CALM) buoy to assist with offloading. The CALM buoy arrived in Ghana early in 2020 and following a series of delays, related to the impacts of COVID-19 and some equipment issues, the buoy and one of two offloading lines were installed at the end of 2020 and fully commissioned in early 2021. The tanker support vessels on contract since 2016 have now been released resulting in anticipated operating expense savings of $60 million (gross) per annum going forwards. Options for the potential need for and installation of a second offloading line are being considered.

Non-operated portfolio

Production from Tullow's non-operated portfolio averaged 22,400 bopd in 2020. Overall production in the first half of 2020 was stable at close to 24,000 bopd. However, in August 2020, the Simba field was required to be shut in to comply with the Gabon Government's OPEC+ quota. The field was shut-in for a total of two months having an annualised impact on Group production of c. 1,000 bopd.

In February 2021, Tullow announced an agreement to sell its entire interests in Equatorial Guinea and the Dussafu assets in Gabon to Panoro Energy ASA (Panoro) for up to $180 million. These value accretive transactions will strengthen the balance sheet and enable the Group to focus on less capital intensive, higher margin assets elsewhere in the West Africa portfolio. The deal, with an effective date of 1 July 2020, is expected to complete in the first half of 2021 and will represent the sale of c.6,000 bopd and c.20 million barrels of 2P reserves.

In mid-January 2021, following a major incident aboard the CNR operated Espoir field FPSO in Côte d'Ivoire, production was shut in for approximately four weeks. Production is now returning to full capacity.

Decommissioning

Asset removal and sea-bed clearance activities in Tullow-operated licences in the UK North Sea were completed in the fourth quarter of 2020. Final surveys are planned in order to close out the operated decommissioning programme this year. The Group's non-operated decommissioning activities are ongoing and are expected to continue through to 2025.

In Mauritania, decommissioning of the Chinguetti field wells was suspended from March 2020 to January 2021, following the Government's decision to close the borders due to COVID-19. Planning and engineering for the decommissioning in Tullow-operated licences at the Banda and Tiof fields is in progress with operations expected to commence in the fourth quarter of 2021, subject to Government approval. The overall Mauritania decommissioning programme, scheduled to complete in 2022, is however anticipated to increase in cost by c.$30 million over the next two years, an increase of $15 million since the CMD, due to COVID-related costs and a new requirement for increased levels of seabed clearance.

In aggregate, the Group's decommissioning expenditure is forecast to be c.$100 million per annum for 2021 and 2022, decreasing to less than $20 million per annum for the subsequent three years.

Kenya

Throughout 2020, Tullow worked closely with its joint venture partners to progress the full field development plan. In August 2020, Force Majeure notices that had applied since May 2020 were withdrawn by Tullow and the joint venture partners. In September 2020, the Government of Kenya agreed to an initial extension for the 10BB and 13T licence blocks until 31 December 2020 and in December 2020, following approval of the 2021 Work Programme and Budget, granted a full extension until 31 December 2021 by which date the Group is required to submit a Field Development Plan.

At the CMD, Tullow announced a joint decision to re-assess the development plan and design a project that is economic at low oil prices whilst preserving the phased development concept. Tullow and its joint venture partners expect to complete a revised assessment of the project by the second quarter of 2021.

During 2020, the Early Oil Pilot Scheme (EOPS) successfully completed two years of production and all the required reservoir and production data gathering was completed as planned. Tullow and the joint venture partners then closed down EOPS and demobilisation of all rental equipment was completed. The reservoir and production data gathered during EOPS is now being used in redesigning the full field development concept. EOPS production of more than 350,000 barrels of oil from the Ngamia and Amosing fields provided six months' sustained rate and pressure data. The data confirms reservoir quality and continuity in both fields, enabling the Group to optimise plans to focus on the most productive wells at the crest of the fields, leading to improved rates per well and refined injector/producer patterns. The impact of this on plateau rates and recoverable resources is being assessed.

In parallel, the joint venture partners are also working closely with the Government of Kenya on securing approval of the Environmental and Social Impact Assessments and finalising the commercial framework for the project.

Separately, the farm down process was suspended in mid-2020 to allow time for the joint venture partners to complete their comprehensive review of the development concept, following which Tullow will assess its strategic options.

Uganda

On 23 April 2020, Tullow agreed the sale of its assets in Uganda to Total for $500 million in cash on completion plus $75 million in cash following the Final Investment Decision (FID) and incremental post first oil contingent payments linked to oil prices over $62/bbl. On 28 May 2020 CNOOC Uganda Limited informed both Tullow and Total that it had elected not to exercise its pre-emption rights. On 18 June 2020 Tullow published the shareholder circular relating to the transaction and on 15 July 2020 a General Meeting was held, at which the transaction received approval with over 99 per cent of the 56 per cent votes cast in favour.

On 6 August 2020 the Government of Uganda provided their consent to the transfer of operatorship from Tullow to Total and on 21 October 2020, Tullow announced that the Government of Uganda and the Ugandan Revenue Authority had executed a binding Tax Agreement that reflected the pre-agreed principles on the tax treatment of the sale of Tullow's Ugandan assets to Total. The Ugandan Minister of Energy and Mineral Development also approved the transfer of Tullow's interests to Total and the transfer of operatorship for Block 2. Consequently, the sale of the Uganda assets to Total completed on 10 November 2020 with $500 million consideration received on the same day.

Based on recent disclosures from Total at their Full Year results, Tullow expects FID for the Lake Albert Development to be taken this year which would trigger the $75 million payment to Tullow.

Exploration

At its CMD, Tullow stated that its focus in exploration was twofold. First, Tullow's exploration team will fully evaluate the prospective net risked resources of 900 million barrels of oil equivalent in emerging basins in Suriname, Guyana, Argentina, Namibia and Côte d'Ivoire. Secondly, the team will work to support Tullow's established producing operations in West Africa through near-field and infrastructure-led exploration.

In 2020, the Group withdrew from its exploration licences in Jamaica and the Comoros Islands and significantly reduced its footprint in onshore Côte d'Ivoire and Peru.

In January 2020, Tullow drilled the Carapa-1 well in the Kanuku licence, offshore Guyana. Although the well was uncommercial on a standalone basis, the result extended the prolific Cretaceous light oil play into the Group's Guyana acreage, across both the Kanuku and Orinduik blocks. Tullow is now working with its joint venture partners on the overall prospect inventory and developing plans to unlock value from this acreage.

In February 2020, Tullow drilled the unsuccessful Marina-1 well in the Z-38 licence offshore Peru, which encountered only light gas shows and Tullow is now exiting this licence.

In Suriname, the Goliathberg-Voltzberg North well in Block 47 is drilling currently and is targeting two prospective intervals in a Cretaceous turbidite play in approximately 1,900 metres of water. The well is being drilled by the Stena Forth drillship and a result is expected in the second quarter of 2021.

A multi-client seismic acquisition in Argentina commenced in the fourth quarter of 2019 over the Tullow-operated MLO 114 and 119 licences but was suspended in May 2020. This campaign re-started in late 2020 and is due to complete by the end of the first quarter of this year.

FINANCE REVIEW

Financial summary	2020	2019
Working interest production volume (boepd)[1]	74,900	86,800
Sales volume (boepd)	74,600	74,000
Realised oil price ($/bbl)	50.9	62.4
Total revenue ($m)	1,396	1,683
Gross profit ($m)	403	759
Underlying cash operating costs per boe ($/boe)[2]	12.1	11.1
Exploration costs written off ($m)	987	1,253
Impairment of property, plant and equipment, net ($m)	251	781
Operating loss($m)	(1,018)	(1,385)
Loss before tax ($m)	(1,273)	(1,653)
Loss after tax ($m)	(1,222)	(1,694)
Basic loss per share (cents)	(86.6)	(120.8)
Capital investment ($m)[2]	288	490
Adjusted EBITDAX ($m)[2]	804	1,398
Net debt ($m)[2]	2,376	2,806
Gearing (times)[2]	3.0	2.0
Free cash flow ($m)[2]	432	355
Underlying operating cash flow ($m) [2]	598	1,166
Pre-financing cash flow ($m) [2]	625	574

1. Including the impact of production-equivalent insurance payments from the Jubilee field, Group working interest production was 74,900 boepd (2019: 86,800 boepd) including working interest gas production of nil boepd (2019: 100 boepd).
2. Alternative performance measures are explained and reconciled on pages 26 to 29.

Production and commodity prices

Total Group working interest production averaged 74,900 boepd, a decrease of 12 per cent for the year (2019: 84,880 boepd). The decrease resulted from field decline and water cut in Ghana, partially offset by higher uptime on Jubilee. There have also been Opec+ enforced production cuts impacting certain Gabon fields.

The Group's realised oil price after hedging was $50.9/bbl and $42.9/bbl before hedging (2019: $62.4/bbl and $64.3/bbl respectively). The impact of the COVID-19 pandemic on global oil demand resulted in depressed oil prices during 2020 and significant discounts to the Dated Brent benchmark oil price for the cargoes sold during April and May 2020. Low oil prices led to a gain on the realisation of commodity hedges, increasing total revenue by $219 million (2019: loss of $53 million).

Underlying cash operating costs, depreciation, impairments, write-offs and administrative expenses

Underlying cash operating costs amounted to $332 million; $12.1/boe (2019: $351 million; $11.1/boe). The 9 per cent increase in unit cash operating costs was principally due to lower production and increased operational costs incurred associated with COVID-19 which was partially offset by a reduction in underlying operating costs in the TEN and Jubilee fields.

Depreciation, depletion and amortisation (DD&A) charges on production and development assets amounted to $446 million; $16.3/boe (2019: $696 million; $22.0/boe). This decrease in DD&A per barrel is mainly attributable to 2019 and 1H20 impairments.

The Group recognised a net impairment charge on producing assets of $251 million in respect of 2020 (2019: $781 million). Impairments were primarily due to indicators of impairments identified in 1H20 as a result of a reduction in short, mid and long-term prices. In 2H20 an impairment reversal was recorded in respect of TEN and Espoir resulting in a full year impairment/reversal of $149 million and $(2.1) million respectively. This was as a result of increased booked 2P reserves and in the case of TEN additionally due to lower future capex assumptions associated with well costs.

The total exploration cost write-offs for the year ended 31 December 2020 were $987 million (2019: $1,253 million), predominantly driven by a write-down of the value of Kenya due to a reduction in the Group's long-term accounting oil price assumption from $65/bbl to $60/bbl and Uganda was written down to the fair value of the consideration as part of the disposal. The remaining write-offs include Marina-1 well costs in Peru and the write-off of licence level costs associated with Peru, Comoros, Côte d'Ivoire and Namibia due to lower levels of planned activity and licence exits.

Administrative expenses of $87 million (2019: $112 million) included an amount of $21 million (2019: $22 million) associated with share-based payment charges. The decrease in administrative expenses primarily relates to lower payroll costs due to the organisational restructuring. The organisational restructuring, which was completed in 2020, is expected to deliver sustainable cash savings of over $125 million per annum.

Restructuring costs and provisions for onerous leases

Changes to provisions in 2020 resulted in an income statement charge of $93 million (2019: charge of $4.2 million). The 2020 charge mainly relates to costs associated with the organisational restructuring which include redundancy and charges for onerous office contracts. Of the $93 million provided for in 2020, $58 million was paid in cash.

Disposals

During 2020 the Group completed the disposal of its interests in Uganda for upfront cash consideration of $500 million, with $75 million due on FID and additional contingent future payments linked to oil prices. On completion $514 million was received in cash, representing the upfront consideration plus $14 million of completion adjustments. The $75 million payment due on FID has been recorded as a current receivable as it is expected to be received in 2021. After deducting transaction costs paid in 2020, net cash proceeds on disposal were $513.4 million.

Derivative financial instruments

Tullow continues to undertake hedging activities as part of its ongoing financial risk management 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. Hedging was paused from April to June 2020 due to the very low oil price environment. Hedging restarted in July 2020 but focused only on 2021.

All of the Group's derivatives are Level 2 (2019: Level 2). There were no transfers between fair value levels during the year.

At 31 December 2020, the Group's derivative instruments had a net positive fair value of $2 million (2019: net negative $12 million).

2021 hedge position at 31 December 2020	**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 hedging position at 31 December 2020 was c.2,000 bopd hedged with an average floor price protected of $50.63/bbl. In February 2021, the Group added a further 9,000 bopd of 2022 straight put options. The new average protected level is $41/bbl.

Net financing costs

Net financing costs for the year were $255 million (2019: $267 million). The decrease in financing costs is associated with the reduction in interest on borrowings due to a reduction in the average level of net debt in 2020 compared to 2019 and a reduction in finance costs associated with the TEN FPSO lease. 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 leased assets, offset by interest earned on cash deposits and capitalised borrowing costs.

Taxation

The net tax credit of $52 million (2019: expense of $41 million) primarily relates to tax charges in respect of the Group's production activities in West Africa, as well as UK decommissioning assets, more than offset by deferred tax credits associated with exploration write-offs, impairments and provisions for onerous service contracts.

Based on a loss before tax for the period of $1,273 million (2019: loss of $1,653 million), the effective tax rate is 4.1 per cent (2019: negative 2.4 per cent). After adjusting for non-recurring amounts related to restructuring costs, exploration write-offs, disposals, impairments, provisions for onerous service contracts and their associated deferred tax benefit, the Group's adjusted tax rate is 35.6 per cent (2019: 70.3 per cent). The adjusted tax rate has decreased due to utilisation of previously unrecognised losses in the UK and prior year adjustments offset by the impact of withholding tax.

The Group's future statutory effective tax rate is sensitive to the geographic mix in which pre-tax profits and exploration costs written off arise. Unsuccessful exploration is often incurred in jurisdictions where the Group has no taxable profits such that no related tax benefit results. Consequently, the Group's tax charge will continue to vary according to the jurisdictions in which pre-tax profits and exploration cost write-offs occur.

Loss after tax from continuing activities and loss per share

The loss for the year from continuing activities amounted to $1,222 million (2019: $1,694 million loss). Basic loss per share was 86.6 cents (2019: 120.8 cents loss).

Reconciliation of net debt

	$m
Year-end 2019 net debt	**2,805.5**
Sales revenue	(1,396.1)
Operating costs	331.7
Other operating and administrative expenses	376.7
Cash flow from operations	**687.7**
Movement in working capital	(118.4)
Tax paid	107.5
Purchases of intangible exploration and evaluation assets and property, plant and equipment	430.9
Other investing activities	(515.2)
Other financing activities	356.7
Foreign exchange loss on cash	(3.7)
Year end 2020 net debt	**2,375.6**

Capital investment

Capital expenditure amounted to $288 million (2019: $490 million) with $206 million invested in development activities and $82 million invested in exploration and appraisal activities. This includes $7 million of capital expenditure associated with Uganda which was reimbursed by Total on completion of the Uganda Transaction.

Tullow will continue to focus on capital discipline with 2021 capital investment largely directed at maximising value from the Group's producing assets. The Group's 2021 capital expenditure is expected to total c.$265 million which comprises Ghana capex of c.$140 million primarily associated with the reinstatement of drilling in 2021, West Africa non-operated capex of c.$60 million, Kenya capex of c.$5 million, and exploration capex of c.$60 million.

Borrowings

During the year, commitments under Tullow's RBL facility reduced from $2,400 million to $1,980 million following voluntary cancellations of commitments in March and in May. Tullow's debt facilities further include $300 million convertible notes due in 2021, $650 million senior notes due in 2022 and $800 million senior notes due in 2025. Liquidity headroom of unutilised debt capacity and free cash was c.$1.1 billion at the end of 2020. Tullow's RBL facility is subject to bi-annual debt capacity redeterminations. In October 2020, Tullow requested a redetermination to commence following the CMD and to complete in January 2021. Tullow subsequently agreed with the lenders under the RBL Facility to an extension of the January 2021 redetermination date by up to one month. The redetermination concluded in early March with $1.7 billion debt capacity approved by the lending syndicate.

On 26 February 2021, the Group submitted a liquidity forecast test to the lenders in respect of the February 2021 RBL redetermination. The Directors concluded that the information submitted to the lenders under the RBL Facility fulfilled the requirements of the liquidity forecast test. At the date of approving the Annual Report and Accounts, an approval in respect of this test is yet to be received, therefore a risk remains that the Group could fail this test.

As at 31 December 2020, the Group has assessed it does not have an unconditional right to defer payment of the RBL facility, Senior Notes due 2022 or Senior Notes due 2025 based on a forecast breach in covenants, as such these borrowings have been classified as current. Refer to going concern disclosure for further details.

Credit ratings

Tullow maintains corporate credit ratings with Standard & Poor's and Moody's Investors Service. In March 2020, Standard & Poor's downgraded Tullow's corporate credit rating to CCC+ from B and assigned a negative outlook; consequently, Standard & Poor's also downgraded the rating of Tullow's corporate bonds to CCC+ from B, in line with the corporate credit rating. In October, Standard & Poor's affirmed the corporate credit rating at CCC+ and revised the outlook to stable. In March, Moody's Investors Service downgraded Tullow's corporate credit rating to B3 from B2 and placed the rating under review for a possible downgrade; consequently, the rating of Tullow's corporate bonds was lowered to Caa2 from Caa1. In November, Moody's Investors Service downgraded Tullow's corporate credit rating to Caa1 from B3 and assigned a negative outlook; the rating of Tullow's corporate bonds remained unchanged at Caa2.

On 5 February 2021 Standard & Poor's placed Tullow's CCC+ corporate credit rating and CCC+ corporate bond rating on negative credit watch.

Liquidity risk management and going concern

Assessment period and assumptions

The Group closely monitors and carefully manages its liquidity risk. Cash flow forecasts are regularly updated, and sensitivities run for different scenarios, including, but not limited to, changes in commodity price and different forecasts for the Group's producing assets. The Directors consider the Going Concern assessment period to be 13 months to April 2022, thereby including the maturity of the $650 million Senior Notes due in April 2022 in the assessment. Management has applied the following oil price assumptions for the Going Concern assessment:

• Base Case: $50/bbl for 2021 and $55/bbl for 2022, and

• Low Case: $45/bbl for 2021 and $50/bbl for 2022.

The Low Case includes, amongst other downside assumptions, an 8% production decrease compared to the Base Case as well as deferred receipts from portfolio management and increased outflows associated with ongoing disputes. No mitigating actions have been included in either case.

The Base Case and Low Case scenarios forecast sufficient financial headroom for the 12 months from approval of the 2020 Annual Report and Accounts on 10 March 2021. However, both scenarios forecast a liquidity shortfall in April 2022 following the repayment of the $650 million Senior Notes due in April 2022, which falls within the liquidity forecast test periods in respect of the February 2021, September 2021 and March 2022 RBL redeterminations. Both cases assume amendments or waivers are received for any forecast Liquidity Forecast Test or gearing covenant breach as described below.

Refinancing Proposal

The Base Case and Low Case scenarios forecast a liquidity shortfall in April 2022, which could result in a failure to pass the Liquidity Forecast Test, as described below, in respect of the February 2021, September 2021 and March 2022 RBL redeterminations, and the gearing covenant tests, as described below, in respect of 30 June 2021 and 31 December 2021. The Group's management has therefore commenced discussions with its existing and potential new creditors, the objective of which is to raise new funding and/or agree certain amendments to the terms, including the covenants and/or maturity dates, of some or all of the RBL Facility, the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes with, if necessary, such amendments being approved by shareholders (Refinancing Proposal). Whilst the Directors believe that a Refinancing Proposal would be in the commercial interests of all stakeholders, there can be no certainty that the creditors and, if necessary, shareholders will agree to a Refinancing Proposal, implementation of which is therefore outside the control of the Group.

Liquidity Forecast Test covenant compliance

As part of each RBL redetermination process the Group is required to demonstrate to the reasonable satisfaction of the relevant majority of its lenders under the RBL Facility that it has, or will have, sufficient funds available to meet the Group's financial commitments for a period of 18 months starting from the first month immediately following the relevant RBL redetermination (Liquidity Forecast Test).

On 26 February 2021 the Group submitted a Liquidity Forecast Test to the lenders in respect of the February 2021 RBL redetermination. The Directors concluded that the information submitted to the lenders under the RBL Facility, which is different from the Base Case and the Low Case scenarios described above and includes mitigating actions, fulfilled the requirements of the Liquidity Forecast Test. At the date of approving the 2020 Annual Report and Accounts, an approval in respect of this test is yet to be received, therefore a risk remains that the Group could fail this test.

If the lenders under the RBL Facility were to conclude that the information submitted does not fulfil the requirements of the Liquidity Forecast Test and the Group was unable to cure the resulting default by the end of April 2021, there would be an event of default. Such event of default would allow the lenders under the RBL Facility, at their discretion, to cancel the RBL Facility and demand that all outstanding borrowings under the RBL Facility be repaid and/or enforce their security rights. This would in turn trigger other creditors' rights to call cross-defaults under the other financing arrangements of the Group (namely the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes) which could result in the entirety of the Group's borrowings potentially becoming immediately repayable by the end of April 2021. While discussions in respect of a Refinancing Proposal are continuing the Directors believe that, if required, a waiver of such a potential event of default in respect of the Liquidity Forecast Test could be agreed with the lenders under the RBL Facility.

The Group is also required to submit Liquidity Forecast Tests in respect of the September 2021 and March 2022 RBL redeterminations. The Base Case and Low Case scenarios forecast, before mitigations, a potential liquidity shortfall and therefore a potential failure of these tests. However, the Directors believe that a Refinancing Proposal could be implemented in time for the September 2021 RBL redetermination such that no shortfall will be forecast as part of the Liquidity Forecast Tests in September 2021 and March 2022. If no Refinancing Proposal has been implemented, and refinancing discussions were no longer continuing, by September 2021 there would be a significant risk of the Group entering into, or being in, insolvency proceedings, the implications of which are described in the section Implications and material uncertainties below.

Gearing covenant compliance

The RBL Facility contains a gearing covenant which is tested for each 12-month period ending on 30 June and 31 December each year, and which requires that net debt of the Group as defined in the RBL Facility agreement is lower than 3.5 times consolidated EBITDAX (earnings before interest tax, depreciation and exploration write-offs) for each relevant 12-month period. Under both the Base Case and the Low Case scenarios, the Group's gearing is forecast to be in excess of the RBL gearing covenant when calculated at 30 June 2021 and 31 December 2021, the two testing dates falling within the Going Concern assessment period.

The Group has requested an amendment in respect of these gearing covenant testing dates as part of the Refinancing Proposal described above. In the event that such amendments are not agreed on time for the testing date falling on 30 June 2021, the Directors would expect to request a waiver or amendment for that testing date only in the first instance, and if needed for the testing date falling on 31 December 2021 in the second half of the year. The Directors believe that the Group would be able to secure such amendments or waivers, which would be both consistent with past practice and the Directors' reasonable expectation of the commercial interests of the Group and its lenders.

If the Group is unable to agree an amendment or waiver of the gearing covenant, if required, in respect of the 30 June 2021 testing date, the Directors will deliver to the relevant lenders a notification of non-compliance, which is required to be delivered as soon as the Group's unaudited financial statements for the half year ended 30 June are available, but no later than 28 September 2021. If a subsequent 75-day period expires without the Company having resolved the non-compliance there will be an event of default under the RBL Facility by mid-December 2021.

Implications and material uncertainties

The Directors note that implementing a Refinancing Proposal or obtaining amendments or waivers in respect of covenant breaches is outside the control of the Group. If the Directors are unable to implement a Refinancing Proposal or, if necessary, obtain amendments or waivers in respect of covenant breaches, the ability of the Group to continue trading would depend upon the Group being able to negotiate a financial restructuring proposal with its creditors and, if necessary, that proposal being approved by shareholders. Whilst the Board would seek to negotiate such a financial restructuring proposal with its creditors, there is no certainty that the creditors would engage with the Board in those circumstances. There would therefore be a significant risk of the Group entering into insolvency proceedings, which the Directors consider would likely result in limited or no value being returned to shareholders.

The Directors have concluded that the uncertainties 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, are material uncertainties that may cast significant doubt that the Group will be able to continue as a Going Concern. Notwithstanding these material uncertainties, the Board's confidence in the Group's ability to implement a Refinancing Proposal supports the preparation of the financial statements on a Going Concern basis. The financial statements do not include the adjustments that would result if the Group were unable to continue as a Going Concern.

Events since 31 December 2020

The six-monthly redetermination of Tullow's Reserves Based Lending (RBL) facility was originally expected to conclude at the end of January. Tullow and its lending banks agreed to extend the process by up to one month, which allowed for additional time to review Tullow's new business plan and operating strategy. Tullow has now received approval for a new debt capacity amount under the facility of $1.7 billion.

On 9 February 2021, Tullow announced that it had signed two separate sale and purchase agreements with Panoro for all of Tullow's assets in Equatorial Guinea (the EG Transaction) and the Dussafu asset in Gabon (the Dussafu transaction) for up to $180 million consisting of up to $105 million for the EG Transaction, up to $70 million for the Dussafu Transaction and a further $5 million consideration to be paid after both transactions have completed. The EG Transaction constitutes a Class 1 transaction under the UK Listing Rules and is subject to the approval of Tullow's shareholders. The Dussafu Transaction constitutes a Class 2 transaction and therefore does not require shareholder approval. Completion of the EG Transaction and the Dussafu Transaction are not inter-conditional. However, both transactions are subject to customary government and other approvals.

On 2 March 2021, further to the announcement made on 9 February 2021, Tullow published the shareholder circular relating to the EG Transaction having received approval from the Financial Conduct Authority. The General Meeting to approve the transaction will take place on 18 March 2021.

Group income statement

Year ended 31 December 2020

$m	Notes	2020	2019
Continuing activities			
Sales revenue		1,396.1	1,682.6
Other operating income – lost production insurance proceeds	7	–	42.7
Cost of sales	5	(993.6)	(966.7)
Gross profit		402.5	758.6
Administrative expenses	5	(86.7)	(111.5)
(Loss)/gain on disposal		(3.4)	6.6
Exploration costs written off	10	(986.7)	(1,253.4)
Impairment of property, plant and equipment, net	11	(250.6)	(781.2)
Restructuring costs and provisions for onerous contracts	5	(92.8)	(4.2)
Operating loss		(1,017.7)	(1,385.1)
Loss on hedging instruments		(0.8)	(1.5)
Finance revenue	6	59.4	55.5
Finance costs	6	(314.3)	(322.3)
Loss from continuing activities before tax		(1,273.4)	(1,653.4)
Income tax credit/(expense)	8	51.9	(40.7)
Loss for the year from continuing activities		(1,221.5)	(1,694.1)
Attributable to			
Owners of the Company		(1,221.5)	(1,694.1)
Loss per ordinary share from continuing activities		¢	¢
Basic		(86.6)	(120.8)
Diluted		(86.6)	(120.8)

Group statement of comprehensive income and expense

Year ended 31 December 2020

$m	2020	2019
Loss for the year from continuing activities	(1,221.5)	(1,694.1)
Items that may be reclassified to the income statement in subsequent periods		
Cash flow hedges		
Gain/(loss) arising in the year	271.0	(118.6)
Losses arising in the period – time value	(37.3)	(73.6)
Reclassification adjustments for items included in profit on realisation	(268.1)	(7.6)
Reclassification adjustments for items included in loss on realisation – time value	49.4	61.0
Exchange differences on translation of foreign operations	(5.3)	(3.5)
Other comprehensive income/(expense)	9.8	(142.3)
Tax relating to components of other comprehensive (expense)/income	(2.7)	–
Other comprehensive income/(expense) for the year	7.1	(142.3)
Total comprehensive expense for the period	**(1,214.4)**	(1,836.4)
Attributable to		
Owners of the Company	(1,214.4)	(1,836.4)

Group balance sheet

As at 31 December 2020

$m	Notes	2020	2019
Assets			
Non-current asset			
Intangible exploration and evaluation assets	10	368.2	1,764.4
Property, plant and equipment	11	3,237.9	3,891.7
Other non-current assets	12	547.4	623.2
Derivative financial instruments		2.6	3.1
Deferred tax assets		494.3	517.5
		4,650.4	6,799.9
Current assets			
Inventories		96.1	191.5
Trade receivables		79.0	38.7
Other current assets	12	717.1	928.7
Current tax assets		36.4	42.9
Derivative financial instruments		17.2	0.7
Cash and cash equivalents		805.4	288.8
Assets classified as held for sale	13	155.6	–
		1,906.8	1,491.3
Total assets		6,557.2	8,291.2
Liabilities			
Current liabilities			
Trade and other payables	14	(750.7)	(1,127.6)
Provisions	15	(229.8)	(172.8)
Borrowings		(3,170.5)	–
Current tax liabilities		(52.2)	(159.6)
Derivative financial instruments		(17.8)	(14.8)
Liabilities directly associated with assets classified as held for sale	13	(187.3)	–
		(4,408.3)	(1,474.8)
Non-current liabilities			
Trade and other payables	14	(1,064.7)	(1,212.9)
Borrowings		–	(3,071.7)
Provisions	15	(620.9)	(753.6)
Deferred tax liabilities		(673.3)	(793.4)
Derivative financial instruments		–	(1.2)
		(2,358.9)	(5,832.8)
Total liabilities		(6,767.2)	(7,307.6)
Net (liabilities)/ assets		(210.0)	983.6
Equity			
Called up share capital		211.7	210.9
Share premium		1,294.7	1,294.7
Equity component of convertible bonds		48.4	48.4
Foreign currency translation reserve		(247.4)	(242.1)
Hedge reserve		4.8	4.6
Hedge reserve – time value		(5.4)	(17.5)
Merger reserve		755.2	755.2
Retained earnings		(2,272.0)	(1,070.6)
Equity attributable to equity holders of the Company		(210.0)	983.6
Total equity		(210.0)	983.6

Group statement of changes in equity (restated)

Year ended 31 December 2020

$m	Called up share capital	Share premium	Equity component of convertible bonds	Foreign currency translation reserve[1]	Hedge reserve	Hedge reserve – time value[2]	Merger reserves	Retained earnings	Total
At 1 January 2019 (previously reported)	209.1	1,344.2	48.4	(238.6)	130.8	(4.9)	755.2	649.0	2,893.2
Restatement[3]	–	(49.5)	–	–	–	–	–	49.5	–
At 1 January 2019 (as adjusted)	209.1	1,294.7	48.4	(238.6)	130.8	(4.9)	755.2	698.5	2,893.2
Profit for the year	–	–	–	–	–	–	–	(1,694.1)	(1,694.1)
Hedges, net of tax	–	–	–	–	(126.2)	(12.6)	–	–	(138.8)
Currency translation adjustments	–	–	–	(3.5)	–	–	–	–	(3.5)
Exercise of employee share options [3]	1.8	–	–	–	–	–	–	(1.8)	–
Share-based payment charges	–	–	–	–	–	–	–	27.7	27.7
Dividends paid	–	–	–	–	–	–	–	(100.9)	(100.9)
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 year	–	–	–	–	–	–	–	(1,221.5)	(1,221.5)
Hedges, net of tax	–	–	–	–	0.2	12.1	–	–	12.3
Currency translation adjustments	–	–	–	(5.3)	–	–	–	–	(5.3)
Exercise of employee share options	0.8	–	–	–	–	–	–	(0.8)	–
Share-based payment charges	–	–	–	–	–	–	–	20.9	20.9
At 31 December 2020	211.7	1,294.7	48.4	(247.4)	4.8	(5.4)	755.2	(2,272.0)	(210.0)

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 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 a $49.5 million and $35.8 million impact on the opening position as at 1 January 2019 and on the options issued in 2019 respectively.

Group cash flow statement

Year ended 31 December 2020

$m	Notes	2020	2019
Loss for the year from continuing activities		(1,273.4)	(1,653.4)
Adjustments for:			
Depreciation, depletion and amortisation	11	467.1	724.6
Loss/(gain) on disposal		3.4	(6.6)
Exploration costs written off	10	986.7	1,253.4
Impairment of property, plant and equipment, net	11	250.6	781.2
Restructuring costs and provision for onerous contracts		92.8	(0.4)
Payment under restructuring costs and provision for onerous contracts	15	(58.4)	(20.4)
Decommissioning expenditure	15	(57.7)	(75.1)
Share-based payment charge		20.9	24.8
Loss on hedging instruments		0.8	1.5
Finance revenue	6	(59.4)	(55.5)
Finance costs	6	314.3	322.3
Operating cash flow before working capital movements		687.7	1,296.4
Decrease in trade and other receivables		195.2	241.4
Decrease/(increase) in inventories		85.1	(56.6)
Decrease in trade payables		(161.9)	(131.5)
Cash generated from operating activities		806.1	1,349.7
Income taxes paid		(107.5)	(91.0)
Net cash from operating activities		698.6	1,258.7
Cash flows from investing activities			
Proceeds from disposals	9	513.4	7.0
Purchase of intangible exploration and evaluation assets		(213.6)	(259.4)
Purchase of property, plant and equipment		(217.3)	(261.5)
Interest received		1.8	1.9
Net cash from/ (used)in investing activities		84.3	(512.0)
Cash flows from financing activities			
Repayment of borrowings		(185.0)	(520.0)
Drawdown of borrowings		270.0	375.0
Payment of obligations under leases		(158.2)	(172.1)
Finance costs paid		(198.5)	(215.4)
Dividends paid		–	(100.9)
Net cash used in financing activities		(271.7)	(633.4)
Net increase in cash and cash equivalents		511.3	113.3
Cash and cash equivalents at beginning of year		288.8	179.8
Foreign exchange gain/(loss)		5.4	(4.3)
Cash and cash equivalents at end of year		805.4	288.8

Notes to the financial statements

Year ended 31 December 2020

1. Basis of preparation and presentation of financial information

Whilst the financial information in this preliminary announcement has been prepared in accordance with International Financial Reporting Standards (IFRS) and International Financial Reporting Interpretation Committee (IFRIC) interpretations adopted for use by the European Union, with those parts of the Companies Act 2006 applicable to companies reporting under IFRS and with the requirements of the United Kingdom Listing Authority (UKLA) Listing Rules, this announcement does not contain sufficient information to comply with IFRS. The Group will publish full financial statements that comply with IFRS in April 2021.

The financial information for the year ended 31 December 2020 does not constitute statutory accounts as defined in sections 435 (1) and (2) of the Companies Act 2006. Statutory accounts for the year ended 31 December 2019 have been delivered to the Registrar of Companies and those for 2020 will be delivered following the Company's annual general meeting. The auditor has reported on these accounts; their reports were unqualified though they drew attention to material uncertainties related to going concern. Their report did not include a reference to any other matters to which the auditor drew attention by way of emphasis of matter and did not contain a statement under section 498 (2) or (3) of the Companies Act 2006.

The Financial Statements have been prepared on the historical cost basis, except for derivative financial instruments, share based payments, and contingent consideration that have been measured at fair value and assets classified as held for sale which are carried at fair value less cost to sell. The Financial Statements are presented in US dollars and all values are rounded to the nearest $0.1 million, except where otherwise stated.

The accounting policies applied are consistent with those adopted and disclosed in the Group's financial statements for the year ended 31 December 2019. There have been a number of amendments to accounting standards and new interpretations issued by the International Accounting Standards Board which were applicable from 1 January 2020, however these have not any impact on the accounting policies, methods of computation or presentation applied by the Group. Further details on new International Financial Reporting Standards adopted will be disclosed in the 2020 Annual Report and Accounts.

Certain new accounting standards and interpretations have been published that are not mandatory for 31 December 2020 reporting periods and have not been early adopted by the Group. These standards are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

2. Loss per share

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

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

The adjustment in respect of convertible bonds and share options had an anti-dilutive impact on earnings and was thus not considered in determining diluted underlying EPS for the year ended 31 December 2020 and 2019.

3. 2020 Annual Report and Accounts

The 2020 Annual Report and Accounts will be mailed in April 2021 only to those shareholders who have elected to receive it. Otherwise, shareholders will be notified that the Annual Report and Accounts are available on the Group's website (www.tullowoil.com). Copies of the Annual Report and Accounts will also be available from the Company's registered office at Building 9, Chiswick Park, 566 Chiswick High Road, London, W4 5XT.

4. Segmental reporting

During 2020, the Group reorganised its operational and organisational structure so that the management and resources of the business are better aligned with the delivery of the business objectives. As a result, the information reported to the Group's Chief Executive Officer for the purposes of resource allocation and assessment of segment performance has changed to focus on four new Business Units – Ghana, Non-operated producing assets including Uganda and decommissioning assets, Kenya and Exploration. Therefore, the Group's reportable segments under IFRS 8 are Ghana, Non-operated, Kenya and Exploration.

The following tables present revenue, loss and certain asset and liability information regarding the Group's reportable business segments for the years ended 31 December 2020 and 31 December 2019.The table for the year ended 31 December 2019 has been restated to reflect the new reportable segments of the business

$m	Ghana	Non-Operated	Kenya	Exploration	Corporate	Total
2020						
Sales revenue by origin	963.5	432.6	–	–	–	(1,396.1)
Segment result[1]	124.9	(410.2)	(430.0)	(104.3)	(15.2)	(834.8)
Loss on disposal						(3.4)
Unallocated corporate expenses[2]						(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 amortisation	(390.1)	(60.7)	(1.5)	–	(14.8)	(467.1)
Impairment of property, plant and equipment, net	(149.1)	(100.5)	–	(0.4)	(0.6)	(250.6)
Exploration costs written off	(0.8)	(452.0)	(430.0)	(103.9)	–	(986.7)

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

Reconciliation of segment result	2020	2019
Segment result	(834.8)	(1,276.0)
Add back:		
Exploration costs written off	986.7	1,253.4
Impairment of Property, plant and equipment	250.6	781.2
Gross profit	402.5	758.6

4. Segmental reporting continued

$m	Ghana	Non-Operated	Kenya	Exploration	Corporate	Total
2019 restated						
Sales revenue by origin	1,262.3	420.3	–	–	–	1,682.6
Other operating income – lost production insurance proceeds	–	–	–	–	42.7	42.7
Segment result	(231.3)	(317.6)	(535.8)	(172.3)	(19.0)	(1,276.0)
Gain on disposal						6.6
Unallocated corporate expense						(115.7)
Operating loss						(1,385.1)
Gain on hedging instruments						(1.5)
Finance revenue						55.5
Finance costs						(322.3)
Loss before tax						(1,653.4)
Income tax expense						(40.7)
Loss after tax						(1,694.1)
Total assets	5,777.8	1,451.0	732.2	183.9	146.3	8,291.2
Total liabilities	(3,289.8)	(747.2)	(75.9)	(72.4)	(3,122.3)	(7,307.6)
Other segment information						
Capital expenditure:						
Property, plant and equipment	338.3	97.3	12.8	2.4	77.6	528.4
Intangible exploration and evaluation assets	2.7	53.9	85.5	137.2	–	279.3
Depletion, depreciation and amortization	(612.7)	(88.6)	(1.4)	(0.7)	(21.2)	(724.6)
Impairment of property, plant and equipment, net	(712.8)	(24.6)	–	–	(43.8)	(781.2)
Exploration costs written off	(2.6)	(541.5)	(535.8)	(173.5)	–	(1,253.4)

5. Other costs

$m	2020	2019
Cost of sales		
Operating costs	331.7	351.3
Depletion and amortisation of oil and gas assets[1]	446.4	696.1
Underlift, overlift and oil inventory movement	160.5	(137.3)
Share-based payment charge included in cost of sales	0.9	2.6
Other cost of sales	54.1	54.0
Total cost of sales	993.6	966.7
Administrative expenses		
Share-based payment charge included in administrative expenses	20.0	22.2
Depreciation of other fixed assets	20.7	28.5
Other administrative costs	46.0	60.8
Total administrative expenses	86.7	111.5
Total restructuring costs and provision for onerous contracts[2]	92.8	4.2

1. Depreciation expense on leased assets of $72.4 million as per note 10 includes a charge of $8.3 million on leased administrative assets, which is presented within administrative expenses in the income statement. The remaining balance of $64.1 million relates to other leased assets and is included within cost of sales.
2. This includes restructuring costs of $4.2 million and redundancy costs of $63.5 million as well as provisions for onerous contacts.

6. Net financing costs

$m	2020	2019
Interest on bank overdrafts and borrowings	205.8	216.0
Interest on obligations for leases	91.0	103.5
Total borrowing costs	296.8	319.5
Less amounts included in the cost of qualifying assets	–	(16.3)
	296.8	303.2
Finance and arrangement fees	0.8	0.7
Other Interest expense	3.6	2.1
Unwinding of discount on decommissioning provisions	13.1	16.3
Total finance costs	314.3	322.3
Interest income on amounts due from joint venture partners for leases	(40.6)	(50.0)
Other finance revenue	(18.8)	(5.5)
Total finance revenue	(59.4)	(55.5)
Net financing costs	254.9	266.8

7. Insurance proceeds

Insurance proceeds of $24.8 million were recorded in the year ended 31 December 2020 (2019: $123.8 million). Proceeds related to lost production under the Business Interruption insurance policy of $nil (2019: $42.7 million) were recorded as other operating income – lost production insurance proceeds in the income statement. Proceeds related to compensation for incremental operating costs under the Business Interruption and Hull and Machinery insurance policies of $nil (2019: $4.2 million) were recorded within the operating costs line of cost of sales (see note 4). Proceeds related to compensation for capital costs under the Hull and Machinery insurance policy of $24.8 million (2019: $76.9 million) were recorded within additions to property, plant and equipment (see note 11). Coverage related to the Turret Remediation Project under the Business Interruption insurance policy ended in August 2019 and full and final settlement for the Hull and Machinery claim was reached in December 2019 with the final proceeds received in the first quarter of 2020.

8. Taxation on loss on continuing activities

Analysis of tax (credit)/expense for the year

$m	2020	2019
Current tax		
UK corporation tax	(24.7)	(32.3)
Foreign tax	81.2	192.5
Tax in respect of prior periods	(25.7)	5.2
Total corporate tax	30.8	165.4
UK petroleum revenue tax	(3.4)	–
Total current tax	27.4	165.4
Deferred tax		
UK corporation tax	19.8	91.7
Foreign tax	(85.3)	(262.9)
Tax in respect of prior periods	(11.7)	44.2
Total deferred corporate tax	(77.2)	(127.0)
Deferred UK petroleum revenue tax	(2.1)	2.3
Total deferred tax	(79.3)	(124.7)
Total income tax (credit)/expense	(51.9)	40.7

8. Taxation on loss on continuing activities contd.

Factors affecting tax (credit)/expense for the year

$m	2020	2019
Loss from continuing activities before tax	**(1,273.4)**	(1,653.4)
Tax on loss from continuing activities at the standard UK corporation tax rate of 19% (2019: 19%)	(241.9)	(314.1)
Effects of:		
Non-deductible exploration expenditure	184.4	208.7
Net tax on fair value movements on derivatives	–	(1.3)
Other non-deductible expenses	46.5	18.8
Tax impact of change in discount rate on decommissioning provision	(2.1)	–
Deferred tax asset not recognised	5.5	–
Derecognition of deferred tax previously recognised	0.7	12.4
Utilisation of tax losses not previously recognised	(8.4)	(0.8)
Current year losses for which deferred tax is not recognised	25.5	73.7
Adjustment relating to prior years	(37.4)	49.4
Higher rate of taxation on Norway losses	(6.3)	–
Other tax rates applicable outside the UK and Norway	(37.1)	11.3
PSC expense/ (income) not subject to corporation tax	18.9	(17.2)
Other income not subject to corporation tax	(0.2)	(0.2)
Group total tax (credit)/ expense for the year	(51.9)	40.7

Current tax assets

As at 31 December 2020, current tax assets were $36.4 million (2019: $42.9 million) of which $33.1 million relates to the UK (2019: $42.9 million).

9. Disposals

During 2020 the Group completed the disposal of its interests in Uganda for upfront cash consideration of $500 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 as it is expected to be received in 2021. After deducting transaction costs paid in 2020, net cash proceeds on disposal were $513.4 million.

The Uganda Sale and Purchase Agreement (SPA) signed in 2017 lapsed in 2019 as a result of the failure to agree all aspects of the tax treatment with the Government of Uganda which was a condition to completing the SPA. Following the expiry of the SPA, the Uganda assets of $840.2 million were reclassified from Assets Held for Sale to Intangible assets in 2019. Refer to Note 10.

Book Value of Assets disposed in Uganda	2020
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)
Total assets and liabilities disposed	582.6

10. Intangible exploration and evaluation assets

$m	2020	2019
At 1 January	1,764.4	1,898.6
Additions	170.7	279.3
Disposals	–	(0.4)
Exploration costs written off	(986.7)	(1,253.4)
Net transfer (to)/from assets held for sale	(580.4)	840.2
Currency translation adjustments	0.2	0.1
At 31 December	368.2	1,764.4

Included within 2020 additions is $nil (note 5) of capitalised interest (2019: $16.3 million). The Group only capitalises interest in respect of intangible exploration and evaluation assets where it is considered that development is ongoing.

During 2020, $33.6 million was capitalised and written off in connection to working capital and indirect taxes associated with the Uganda disposal.

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

Country	Rationale for 2020 write-off	2020 pre-tax write off $m	2020 post- tax write off $m	2020 Remaining recoverable amount $m
Kenya	e	430.0	430.0	247.0
Uganda	f	451.4	451.4	–
Comoros	b	12.4	12.4	–
Guyana	a	9.2	9.2	42.2
Peru	b,d	41.2	41.2	–
Cote d'Ivoire	b	14.3	14.3	–
Other	a,c	28.2	28.2	–
Total write-off		986.7	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 per cent (2019: 14%)
f. Written down to the value of the transaction consideration. (Refer to note 9 for further detail)

The Group has received a 15 month licence extension from September 2020 to December 2021 which is contingent on certain conditions. As at 31 December 2020, the Group has complied with all of the conditions which effectively extends the licence extension period to 31 December 2021. One of the conditions requires the Group to submit a technically and commercially compliant Field Development Plan (FDP) with the Government of Kenya by 31 December 2021. If the FDP is not submitted by 31 December 2021, the extension period will expire on 31 December 2021. The Group along with its joint venture partners are working towards the preparation of a technically and commercially compliant FDP in accordance with the PSCs and expects to submit the FDP by 31 December 2021 to further extend the licence.

Oil prices stated in note 11 are benchmark prices to which an individual field price differential is applied. Exploration write-offs for the Kenya development area assessments are prepared on a value-in-use basis using discounted future cash flows based on 2C resource profiles. A reduction or increase in the long-term price assumptions of $5/bbl, based on the range of annualised average historical prices, are considered to be reasonably possible changes for the purposes of sensitivity analysis. Decreases to oil prices would increase the exploration write-off charge by $72.3 million, whilst increases to oil prices specified above would result in a credit to the exploration write-offs of $65.9 million. A 1 per cent increase in the pre-tax discount rate would increase the exploration write-off by $63.7 million. The Group believes a 1 per cent change in the pre-tax discount rate to be a reasonable possibility based on historical analysis of the Group's and a peer group of companies' discount rates.

11. Property, plant and equipment

$m	2020 Oil and gas assets	2020 Other fixed assets	2020 Right of use assets	2020 Total	2019 Oil and gas assets	2019 Other fixed assets[1]	2019 Right of use assets	2019 Total
Cost								
At 1 January	11,279.6	190.6	1,038.5	12,508.7	11,794.0	271.0	–	12,065.0
Adjustment on adoption of IFRS 16	–	–	–	–	(907.7)	–	907.7	–
Additions	203.6	9.6	16.5	229.7	357.1	21.0	150.3	528.4
Disposals	(11.0)	(125.6)	(17.6)	(154.2)	–	(108.4)	(20.6)	(129.0)
Transfer to assets held for sale	(1,050.9)	–	(19.5)	(1,070.4)	–	–	–	–
Currency translation adjustments	38.9	(5.0)	0.7	34.6	36.2	7.0	1.1	44.3
At 31 December	10,460.2	69.6	1,018.6	11,548.4	11,279.6	190.6	1,038.5	12,508.7
Depreciation, depletion, amortisation and impairment								
At 1 January	(8,194.6)	(157.7)	(264.7)	(8,617.0)	(6,951.1)	(197.5)	–	(7,148.6)
Adjustment on adoption of IFRS 16	–	–	–	–	151.5	–	(151.5)	–
Charge for the year	(382.3)	(12.4)	(72.4)	(467.1)	(620.1)	(18.6)	(85.9)	(724.6)
Impairment loss	(250.0)	(0.6)	–	(250.6)	(737.4)	(43.8)	–	(781.2)
Capitalised depreciation	–	–	(23.8)	(23.8)	–	–	(29.0)	(29.0)
Disposal	10.9	122.8	7.1	140.8	–	108.4	1.8	110.2
Transfer to assets held for sale	938.2	–	1.6	939.8	–	–	–	–
Currency translation adjustments	(38.1)	5.6	(0.1)	(32.6)	(37.5)	(6.2)	(0.1)	(43.8)
At 31 December	(7,915.9)	(42.3)	(352.3)	(8,310.5)	(8,194.6)	(157.7)	(264.7)	(8,617.0)
Net book value at 31 December	2,544.3	27.3	666.3	3,237.9	3,085.0	32.9	773.8	3,891.7

1. Other fixed assets in 2019 have been restated to include a derecognition of an asset that was fully impaired during the year ended 31 December 2019. The amount of disposals included in cost and accumulated depreciation of other fixed assets has changed from $0.3 million to $108.4 million.

The currency translation adjustments arose due to the movement against the Group's presentation currency, USD, of the Group's UK assets which have functional currencies of GBP.

	Trigger for 2020 impairment/(reversal)	2020 Impairment/(reversal) $m	Pre-tax discount rate assumption	2020 Remaining recoverable amount $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
Mauritania	c	30.6	n/a	–
Espoir (Cote d'Ivoire)	a.d	(2.1)	10%	81.5
TEN (Ghana)	a.d	149.2	10%	1,510.6
UK CGU	c,e	13.2	n/a	–
Other		6.2	n/a	–
		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 revisions to reserves.
e. The fields in the UK are grouped into one CGU as all fields within those countries share critical gas infrastructure.

In 1H20 impairments recorded in respect of the TEN and Espoir assets of $305.8 million and $12.8 million respectively, were as result of a reduction in short, mid and long-term oil price assumptions. In 2H20 an impairment reversal was recorded in respect of TEN and Espoir resulting in a full year impairment/reversal of $149.2 million and $(2.1) million respectively. This was as a result of increased booked 2P reserves and in the case of TEN lower future capex assumptions associated with well costs.

During 2020 and 2019, 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
2020	$45/bbl	$50/bbl	$55/bbl	$60/bbl	$60/bbl	$60/bbl inflated at 2%
2019	$64/bbl	$60/bbl	$60/bbl	$63/bbl	$65/bbl	$65/bbl inflated by 2%

Oil prices stated above are benchmark prices to which an individual field price differential is applied. All impairment assessments are prepared on a value-in-use basis using discounted future cash flows based on 2P reserves profiles. A reduction or increase in the two-year forward curve of $5/bbl, based on the approximate range of annualized average oil price over recent history, and a reduction or increase in the medium and long-term price assumptions of $5/bbl, based on the range of annualised average historical prices, are considered to be reasonably possible changes for the purposes of sensitivity analysis. Decreases to oil prices specified above would increase the impairment charge by $202.2 million for Ghana and $29.3 million for Non-Operated, whilst increases to oil prices specified above would result in a credit to the impairment charge of $203.9 million for Ghana and $48.5 million for Non-Operated. A 1 per cent increase in the pre-tax discount rate would increase the impairment by $59.0 million for Ghana and reduce the impairment charge by $7.5 million for Non-Operated. The Group believes a 1 per cent change in the pre-tax discount rate to be a reasonable possibility based on historical analysis of the Group's and a peer group of companies' impairment discount rates. The Directors considered that the relevant change in this assumption would have a consequential effect on other key assumptions including cessation of production and cash flows.

12. Other assets

$m	2020	2019
Non-current		
Amounts due from joint venture partners	547.4	576.6
Uganda VAT recoverable	–	33.5
Other non-current assets	–	13.1
	547.4	623.2
Current		
Amounts due from joint venture partners	521.9	711.8
Underlifts	19.5	97.8
Prepayments	60.7	69.5
Other current assets[1]	115.0	49.6
	717.1	928.7

Other current assets mainly include the deferred consideration relating to the Uganda disposal ($75 million) as well as the deferred consideration relating to the Netherlands disposal in 2017 ($10 million) and VAT recoverable ($15 million).

Uganda VAT receivable and other non-current assets were written off in 2020.

13. Assets held for sale

Equatorial Guinea and Dussafu asset in Gabon

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 Exploration and Production Sharing contract in Gabon, in each case with an effective date of 1 July 2020.

Cash consideration of $89 million is payable at completion of the Equatorial Guinea transaction and $46 million payable at completion of the Dussafu Transaction, plus an additional $5 million when both transactions complete.

The major classes of assets and liabilities comprising the assets classified as held for sale as at 31 December 2020 were as follows:

$m	EG 2020	Ruche 2020	Total 2020
Assets			
Property, plant and equipment	76.0	54.6	130.6
Inventories	5.6	1.4	7.0
Other current assets	11.3	6.7	18.0
Assets classified as held for sale	92.9	62.7	155.6
Liabilities			
Trade and other payables	(3.5)	(27.9)	(31.4)
Current tax liabilities	(10.0)	–	(10.0)
Deferred tax liabilities	(16.7)	–	(16.7)
Provisions	(124.3)	(4.9)	(129.2)
Liabilities directly associated with assets classified as held for sale	(154.5)	(32.8)	(187.3)
Net (liabilities)/assets directly associated with disposal group	(61.6)	29.9	(31.7)

Equatorial Guinea and the Dussafu asset in Gabon are included within the Non-operated segment of the Group.

14. Trade and other payables

$m	2020	2019
Current liabilities		
Trade payables	38.3	95.4
Other payables[1]	49.5	95.7
Overlifts	3.8	-
Accruals[2]	409.4	636.1
VAT and other similar taxes	8.9	16.2
Current portion of leases	240.8	284.2
	750.7	1,127.6
Non-current liabilities		
Other non-current liabilities[3]	89.0	75.0
Non-current portion of leases	975.7	1,140.9
	1,064.7	1,212.9

1. Other payables include accrued interest of $40.9 million (2019: $43.2 million).
2. Accruals mainly relate to capital expenditure, interest expense on bonds and loans and staff related expenses.
3. Other non-current liabilities include balances related to joint venture partners.

Payables related to operated Joint Ventures (primarily in Ghana and Kenya) are recorded gross with the amount representing the partners' share recognised in amounts due from joint venture partners (note 12). The change in trade payables and in other payables predominantly represents timing differences and levels of work activity. The reduction in accruals is associated with reduced operational activity in Ghana and the disposal of the Group's interests in Uganda.

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

15. Provisions

$m	Decommissioning 2020	Other provisions 2020	Total 2020	Decommissioning 2019	Other provisions 2019	Total 2019
At 1 January	850.1	76.2	926.3	794.0	81.5	875.5
New provisions and reclassifications	14.9	136.6	151.5	109.0	15.5	124.5
Disposals	–	–	–	–	(0.3)	(0.3)
Transfer to asset and liabilities held for sale	(129.2)	–	(129.2)	–	–	–
Payments	(57.7)	(58.4)	(116.1)	(75.1)	(20.4)	(95.5)
Unwinding of discount	13.1	–	13.1	16.3	–	16.3
Currency translation adjustment	4.9	0.2	5.1	5.9	–	5.9
At 31 December	696.1	154.6	850.7	850.1	76.3	926.4
Current provisions	104.4	125.4	229.8	102.6	70.2	172.8
Non-current provisions	591.7	29.2	620.9	747.5	6.1	753.6

Other provisions include non-income tax provision, restructuring provision and disputed cases and claims. Management estimates non-current other provisions would fall due between two to five years.

The decommissioning provision represents the present value of decommissioning costs relating to the European and African oil and gas interests.

Decommissioning provisions	Inflation assumption	Discount rate assumption 2020	Cessation of production assumption 2020	Total 2020 $m	Discount rate assumption 2019	Cessation of production assumption 2019	Total 2019 $m
Côte d'Ivoire	2%	1%	2031	63.9	2%	2033	55.6
Equatorial Guinea[1]	n/a	n/a	n/a	–	2%	2030-2032	116.1
Gabon[1]	2%	1-1.5%	2027-2037	61.8	2-2.5%	2022-2037	56.7
Ghana	2%	1-1.5%	2034-2036	323.5	2-2.5%	2032-2036	365.6
Mauritania	n/a	n/a	2018	89.0	n/a	2018	82.6
UK	n/a	n/a	2018	157.9	n/a	2018	173.5
				696.1			850.1

1 Decommissioning provision relating to Equatorial Guinea and Ruche (Gabon) transferred to Assets and Liabilities held for Sale (note 13) as at 31 Dec 2020 ($124.3 million and $4.9 million, respectively)

During 2020 the Group lowered its decommissioning discount rate assumptions from 2-2.5% to 1-1.5% in line with the reduction in US Treasury rates.

16. 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	Petroleum mmboe
COMMERCIAL RESERVES[1]											
1 January 2020	170.3	136.6	48.3	10.1	-	-	-	-	218.6	146.7	243.0
Revisions[3]	29.0	42.6	8.0	2.8	-	-	-	-	37.0	45.3	44.6
Production	(19.2)	-	(7.9)	(1.8)	-	-	-	-	(27.1)	(1.8)	(27.4)
31 December 2020	180.1	179.2	48.4	11.1	-	-	-	-	228.5	190.2	260.2
CONTINGENT RESOURCES[2]											
1 January 2020	215.7	691.8	529.8	135.4	170.8	-	47.4	-	963.7	827.2	1,101.6
Revisions[4]	1.3	57.3	(3.2)	(2.6)	-	-	0.3	-	1.7	54.7	7.5
Additions[5]	-	-	-	-	-	-	6.8	-	6.8		6.8
Disposal and relinquishments	-	-	(467.1)	(54.1)	170.8	-	-	-	(467.1)	(54.4)	(476.2)
31 December 2020	217.0	749.1	59.5	78.4	170.8	-	54.5	-	501.7	827.5	639.7
TOTAL 31 December 2020	397.1	928.3	107.9	89.5	170.8	-	54.5	-	730.2	1,017.7	899.9

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 reserves.
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.
3. The revision to reserves relates mainly to improved field performance in both Jubilee and TEN fields, maturation of projects such as Jubilee South East Phase 1 & 2, New Jubilee Acceleration projects, partial expansion, additional gas injector in Ntomme and updated audited volumes in Simba, Ruche and Espoir, offset by production for the full year 2020.
4. The revision to the contingent resources relates mainly to increases at the Gabon asset, maturation from Contingent resources to reserves in both fields in Ghana and the sales of the Uganda asset.
5. The additional contingent resources relate to oil discoveries in Guyana.

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 248.9 mmboe at 31 December 2020 (31 December 2019: 225.1 mmboe). Contingent Resources relate to resources in respect of which development plans are in the course of preparation or further evaluation is under way with a view to future development.

Alternative performance measures

The Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures include capital investment, net debt, gearing, adjusted EBITDAX, underlying cash operating costs 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, capitalised finance costs, additions to administrative assets, Norwegian tax refund and certain other adjustments. The Directors believe that capital investment is a useful indicator of the Group's organic expenditure on Exploration and 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.

$m	2020	2019
Additions to property, plant and equipment	229.7	528.4
Additions to intangible exploration and evaluation assets	170.7	279.3
Less		
Decommissioning asset additions	14.9	109.0
Right-of-use asset additions	16.5	150.3
Lease payments related to capital activities	(4.0)	(2.7)
Capitalised share-based payment charge	–	1.9
Capitalised finance costs	–	16.3
Additions to administrative assets	9.6	21.0
Norwegian tax refund	–	0.9
Other non-cash capital expenditure	75.3	21.0
Capital investment	**288.1**	**490.0**
Movement in working capital	133.2	9.0
Additions to administrative assets	9.6	21.0
Norwegian tax refund	–	0.9
Cash capital expenditure per the cash flow statement	**430.9**	**520.9**

Net debt

Net debt is a useful indicator of the Group's indebtedness, financial flexibility and capital structure because it indicates the level of cash borrowings after taking account of cash and cash equivalents within the Group's business that could be utilised to pay down the outstanding cash borrowings. Net debt is defined as current and non-current borrowings plus non-cash adjustments, less cash and cash equivalents. Non-cash adjustments include unamortised arrangement fees, adjustment to convertible bonds, and other adjustments.

$m	2020	2019
Borrowings	3,170.5	3,071.7
Non-cash adjustments	10.5	22.6
Less cash and cash equivalents	(805.4)	(288.8)
Net debt	**2,375.6**	**2,805.5**

Gearing and Adjusted EBITDAX

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

$m	2020	2019
Loss from continuing activities	(1,221.5)	(1,694.1)
Adjusted for		
Income tax (credit)/expense	(51.9)	40.7
Finance costs	314.3	322.3
Finance revenue	(59.4)	(55.5)
Loss on hedging instruments	0.8	1.5
Depreciation, depletion and amortisation	467.1	724.6
Share-based payment charge	20.9	25.8
Provisions	92.8	4.2
Loss/(gain) on disposal	3.4	(6.6)
Exploration costs written off	986.7	1,253.4
Impairment of property, plant and equipment, net	250.6	781.2
Adjusted EBITDAX	**803.8**	**1,397.5**
Net debt	**2,375.6**	**2,805.5**
Gearing (times)	**3.0**	**2.0**

Underlying cash operating costs

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

$m	2020	2019
Cost of sales	993.6	966.7
Less:		
Depletion and amortisation of oil and gas and leased assets	446.4	696.1
Underlift, overlift and oil stock movements	160.5	(137.3)
Share-based payment charge included in cost of sales	0.9	2.6
Other cost of sales	54.1	54.0
Underlying cash operating costs	**331.7**	**351.3**
Production (MMboe)	27.4	31.7
Underlying cash operating costs per boe ($/boe)	**12.1**	**11.1**

Free cash flow

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

$m	2020	2019
Net cash from operating activities	698.6	1,258.7
Net cash from/(used) in investing activities	84.3	(512.0)
Repayment of obligations under leases	(158.2)	(172.1)
Finance costs paid	(198.5)	(215.4)
Foreign exchange gain/(loss)	5.4	(4.3)
Free cash flow	**431.6**	**354.9**

At the Capital Markets Day in November 2020, the Group presented a revised business plan focusing on the maximisation of value from the Group's producing assets. In order to assess performance against the revised business plan, the Group set out two new alternative performance measures in replacement of Free Cash Flow, Underlying Operating Cash Flow and Pre-financing Cash Flow. These measures will be used from 2021 onwards but are set out below.

Underlying operating Cash Flow and Pre-financing cashflow

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

Pre-financing cash flow is a useful indicator of the Group's ability to generate cash flow to reduce borrowings and provide returns to shareholders through dividends. Pre-Financing cash flow is defined as underlying operating cash flow plus net cash from/(used) in investing activities, decommissioning expenditure and payments to/from decommissioning escrow fund.

$m	**2020**	**2019**
Net cash from operating activities	698.6	1,258.7
Plus		
Decommissioning expenditure	57.7	75.1
Payments to/from decommissioning escrow fund	–	3.8
Less		
Repayment of obligations under leases	(158.2)	(172.1)
Underlying operating cash flow	598.1	1,165.5
Net cash from/(used) in investing activities	84.3	(512.0)
Decommissioning expenditure	(57.7)	(75.1)
Payments to/from decommissioning escrow fund	–	(3.8)
Pre-financing cash flow	624.7	574.6

EVENTS ON THE DAY

In conjunction with these results, Tullow is conducting a virtual presentation webcast that can be watched live or on replay.

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	6889987

WEBCAST

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

https://edge.media-server.com/mmc/p/kz4hpaav

The replay will be available from noon on 10 March 2021.

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Notes to editors

Tullow is an independent oil & gas, exploration and production group, quoted on the London, Irish and Ghanaian stock exchanges (symbol: TLW). The Group has interests in over 50 exploration and production licences across 11 countries.

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

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