Tullow Oil plc

2018
FULL YEAR RESULTS

13 February 2019

TULLOW OIL plc

THIS PRESS RELEASE CONTAINS INSIDE INFORMATION

Tullow Oil plc – 2018 Full Year Results

$1.9 billion sales revenue; $411 million free cash flow; 1.9x gearing; 4.8¢/share final dividend
Ghana gross production c. 180,000 bopd in 2019; FIDs targeted in East Africa
Three-well Guyana drilling campaign to commence mid-year

13 February 2019 – Tullow Oil plc (Tullow), the independent oil and gas exploration and production group, announces its Full Year Results for the year ended 31 December 2018. Details of a presentation in London, webcast and conference calls are available on the last page of this announcement or visit the Group's website www.tullowoil.com.

COMMENTING TODAY, PAUL McDADE, CHIEF EXECUTIVE OFFICER, SAID:

"Tullow has worked hard over the past few years to become a self-funding, cash-generating business with a robust balance sheet, low-cost assets and a rigorous focus on cost and capital discipline. This has allowed us to set a clear capital returns policy which will start with the 2018 final dividend announced today. Our high-margin producing assets in West Africa, substantial development assets in East Africa and exploration licences in industry hotspots provide Tullow with a strong foundation for growth in the years ahead."

2018 FULL YEAR RESULTS SUMMARY

- Revenue of $1.9 billion; corporate Business Interruption insurance proceeds of $188 million
- Gross profit of $1.1 billion; profit after tax of $85 million; free cash flow of $411 million; opex reduced to $10/barrel
- Year-end net debt of $3.1 billion, $1 billion headroom; gearing of 1.9x; no near-term maturities
- 2018 capital investment of $423 million; 2019 forecast of $570 million
- Sustainable capital returns policy announced in November; 2018 final recommended dividend of 4.8¢/share (c.$67 million)
- West Africa 2018 net oil production averaged 88,200 bopd; 2019 forecast 93,000 - 101,000 bopd
- Principles agreed with Government of Uganda on CGT; completion of farm-down to follow
- JV Partners targeting Uganda development FID around mid-year; Kenya development targeting end 2019 FID
- Guyana exploration drilling to commence in mid-2019 with a three-well programme planned

FINANCIAL OVERVIEW

	FY 2018	FY 2017
Total revenue ($m)	1,859	1,723
Other operating income – corporate Business Interruption insurance proceeds ($m)	188	162
Gross profit ($m)	1,082	815
Administrative expenses ($m)	(90)	(95)
Restructuring costs ($m)	(3)	(15)
Gain/(loss) on disposal ($m)	21	(2)
Exploration costs written off ($m)	(295)	(143)
Impairment of property, plant and equipment, net ($m)	(18)	(539)
Provision for onerous service contracts, net ($m)	(167)	1
Operating profit ($m)	528	22
Profit/(loss) after tax ($m)	85	(175)
Free cash flow ($m)	411	543

Note: Underlying cash operating costs per boe, capital investment, net debt, gearing and free cash flow are non-IFRS measures and are explained in the Finance Review.

Corporate Governance Matters

Board changes

On 17 April 2018, Tullow announced that Dorothy Thompson CBE had been appointed as an independent non-executive Director and Chair-designate of Tullow with effect from the conclusion of the Group's Annual General Meeting (AGM). Dorothy Thompson then succeeded Aidan Heavey, Tullow's founder, as Chair of the Group, at the end of the Board meeting on 20 July 2018.

Kevin Massie stepped down as Company Secretary to pursue another role in Tullow at the end of the 2018 AGM. The Board appointed Adam Holland, then Deputy Company Secretary & Senior Legal Advisor, to the role of Company Secretary.

On 6 February 2018, Anne Drinkwater informed the Board that she had decided not to stand for re-election at the 2018 AGM.

Dividend

Tullow held a Capital Markets Day in London on 29 November 2018 and announced a capital returns policy to start from the 2019 financial year. The policy states that the Group intends to pay an annual ordinary dividend based on its free cash flow generation, while ensuring an appropriate balance with debt reduction and investment in the business. It is expected that the total ordinary dividend in any year will be no less than $100 million and will be payable semi-annually, split between the interim and final dividend (1/3:2/3). In periods of particularly strong free cash flow generation, the Board will also look to supplement the ordinary dividend with additional returns to shareholders.

With respect to the 2018 financial year, following another strong year of free cash flow generation, the Board has decided to recommend a final dividend of 4.8¢/share (representing a total shareholder return of c.$67 million) which will be payable in May 2019 if approved at the 2019 AGM.

Change of external auditor

Following a competitive process, the Board have appointed Ernst & Young LLP as Tullow's external auditors. The appointment will be subject to a vote by shareholders at the Group's 2020 AGM and, if passed, will take effect from the end of the meeting.

Annual General Meeting

Tullow's AGM will take place on Thursday 25 April 2019 at 12pm at the Company's offices at Building 9, Chiswick Park, 566 Chiswick High Road, London, W4 5XT.

Ian Springett

The Board regrets to announce that Ian Springett, formerly Chief Financial Officer and a Director of Tullow from 2009-2017, passed away on 16 January 2019. Ian was a great friend and colleague to many at Tullow and beyond and he will be hugely missed. The thoughts and condolences of the Board and all Tullow staff go out to Ian's family and friends.

Operations review

Production

Tullow's West Africa oil assets performed strongly in 2018 and delivered net production of 88,200 bopd. This includes production-equivalent insurance payments of 8,600 bopd received under Tullow's Corporate Business Interruption insurance. Working interest gas production averaged 1,800 boepd giving overall Group net production of 90,000 boepd.

In 2019, overall working interest oil production, including production-equivalent insurance payments, is expected to increase and is forecast to average between 93,000 and 101,000 bopd. Working interest gas production from TEN is expected to average 1,000 boepd.

Overall Group net production is therefore expected to be in the range of 94,000 to 102,000 boepd.

WEST AFRICA

Gary Thompson, Executive Vice President for West Africa, commented today:

> *"Tullow's West African business continues to underpin the Group with strong production performance across all our assets. The TEN fields and the West African non-operated business outperformed substantially in 2018 and with further growth in production to come in 2019, this business is well-positioned to deliver on its full potential."*

Ghana

Drilling programme

Tullow returned to drilling in Ghana in 2018 following the conclusion of proceedings at the ITLOS tribunal in Hamburg in September 2017 and after gaining Government approval of the Greater Jubilee Full Field Development Plan. Tullow began a new drilling programme in March with the Maersk Venturer and a second rig, the Stena Forth, was contracted during the year to work alongside the Maersk Venturer. The second rig was contracted for an initial three-well campaign with flexible extension options reflecting conditions in the rig market which continue today. The Stena Forth began drilling in October 2018 and the additional rig capacity enabled Tullow to carry out simultaneous drilling and completion activity, allowing the tie-in of new wells to be brought forward. The results from this programme, which was completed within budget, were in line with, or exceeded, pre-drill expectations. In 2019, Tullow expects to drill and complete seven new wells across the TEN and Jubilee fields allowing gross oil production from Ghana to rise to around 180,000 bopd.

Jubilee

Gross production for 2018 averaged 78,000 bopd (net: 27,700 bopd) which increases to 36,300 bopd (net) after including 8,600 bopd of net production-equivalent insurance payments. Production from Jubilee was slightly lower than expected. This was due to downtime related to work on the gas compression system in the first half of 2018 and some minor facilities issues towards the end of the year, which have since been resolved. Over the year, two new Jubilee production wells, J51-P and J53-P, were drilled and successfully met all pre-drill expectations. The completion of a water injector, drilled during the previous campaign, was also carried out. These wells were brought on stream in the second half and are accessing highly productive parts of the reservoir.

Tullow expects 2019 average gross oil production from the Jubilee field to increase to around 96,000 bopd (net: 34,000 bopd). Tullow's corporate Business Interruption insurance is expected to provide around 1,000 bopd of net production-equivalent insurance payments, resulting in expected total 2019 Jubilee full year net production of around 35,000 bopd.

Turret Remediation Project

The Turret Remediation Project is close to completion. This pioneering and unique project, which included the first ever remediation of this type at sea, required the FPSO Kwame Nkrumah to be shut down twice in the first half of 2018 for work to stabilise the turret bearing for periods of 19 days and 21 days respectively. In December 2018, the FPSO was successfully rotated to its new heading of 205 degrees and subsequently spread-moored.

The JV Partners have also agreed to install a Catenary Anchor Leg Mooring (CALM) buoy for offtake from the FPSO and a contract award has been made. The installation of the CALM buoy is likely to take place in 2020 and is not expected to affect production.

TEN

The TEN fields performed well in 2018, with gross production averaging 64,500 bopd (net: 30,400 bopd) reflecting good results from the drilling programme. The first additional Ntomme well, NT05-P, was successfully drilled in the first half of the year and started producing in August 2018. A second new producer, EN10-P, is currently being completed and is expected to be online in February.

Tullow expects 2019 gross oil production from the TEN fields to average around 83,000 bopd (net: 39,000 bopd). Tullow is confident of this growth in production following strong performance in 2018, good results from recently drilled wells in both the Ntomme and Enyenra fields and production testing that has seen the TEN FPSO deliver in excess of its design capacity. The forecast includes a two-week shutdown of the TEN FPSO for routine maintenance which is currently scheduled for the second quarter of 2019. Gross gas production is expected to be around 2,100 boepd (net: 1,000 boepd).

Exploration

Tullow has successfully pre-qualified for Ghana's maiden licensing round with bids due by mid-May 2019. The licensing process is expected to conclude by the end of August 2019.

Seadrill and Kosmos litigation

Following a trial in the English Commercial Court in May 2018, the court ruled on 3 July 2018 that Tullow was not entitled to terminate its West Leo rig contract with Seadrill on 4 December 2016 by invoking the contract's force majeure provisions. Following advice from counsel, Tullow decided not to appeal this ruling. Tullow paid Seadrill a contractual termination fee, other standby fees that accrued in the 60 days prior to termination of the contract and interest amounting to $248 million in aggregate.

Although Tullow regards these as JV Partner costs, Kosmos disputed separately, through an International Chamber of Commerce arbitration against Tullow, its share of the liability (c. 20%) of any costs related to the use of the West Leo rig beyond 1 October 2016. On 17 July 2018, the arbitration tribunal delivered a final and binding award in favour of Kosmos which determined that Kosmos is not liable for its share of these costs. As a result of both litigation results, Tullow's net exposure in 2018 was a cash outflow of $208 million.

Non-operated Portfolio and gas production

In 2018, production was strong across the West Africa non-operated portfolio and averaged 21,500 bopd, well ahead of the Group's initial 2018 forecast of 19,000 bopd. The Equatorial Guinea fields performed particularly well in the first half of the year following a change of operator. In Gabon, the Simba development in Gabon has been completed and came on-stream in January. Production in 2019 from the West Africa non-operated portfolio is forecast to be between 22,000 and 24,000 bopd.

Gas production

In 2018, full year net gas production from the TEN fields and the UK averaged 1,700 boepd. In 2019, Tullow will solely produce gas in Ghana following the cessation of production in Tullow's UK assets in 2018.

Decommissioning

The decommissioning programme for the remaining Tullow operated wells in the UK North Sea is expected to have been completed by the third quarter of 2019. Tullow will then undertake final removal and clearance activities to restore the seabed. Tullow ceased production from its non-operated UK North Sea assets during the third quarter of 2018. The decommissioning programme for these assets is expected to be completed by 2025.

In Mauritania, the Chinguetti FPSO (non-operated) was disconnected and demobilised in the first half of 2018. The permanent abandonment programme for the wells in the field will start in mid-2019.

EAST AFRICA

Mark MacFarlane, Executive Vice President for East Africa, commented today:

> *"This year the East Africa team will be driving hard towards two Final Investment Decisions on our East African projects which have the potential to deliver over 50,000 bopd of net production to Tullow by the early 2020s. We are making good progress in both Uganda and Kenya and are focused on delivering on the growth potential that these projects offer."*

Kenya

Development

The Kenya development plan is progressing well, and the project continues to target a Final Investment Decision (FID) in late 2019 and First Oil in 2022.

In February 2018, Tullow announced that following a full assessment of all the exploration and appraisal data, Tullow estimates that the South Lokichar basin contains 240 – 560 – 1,230 million barrels (1C–2C–3C) of recoverable resources from overall discovered oil in place of up to 4 billion barrels. The additional remaining conventional undrilled prospect inventory of the basin is approximately 230 million barrels risked mean recoverable resources, not including further potential in under-explored plays.

Tullow and its JV Partners also proposed to the Government of Kenya that the Amosing, Ngamia and Twiga fields should be developed as the Foundation Stage of the South Lokichar Development. This Foundation Stage includes a 60,000 to 80,000 bopd Central Processing Facility (CPF) and an export pipeline to Lamu. The installed infrastructure from this initial phase is expected to be utilised for the optimisation of the remaining South Lokichar oil fields and future oil discoveries, allowing the incremental development of these fields to be completed at a lower unit cost post First Oil.

Total gross capex associated with the Foundation Stage is expected to be c.$3 billion.

In 2018, the development project gained momentum. Key workstreams relating to Front-end Engineering and Design (FEED) and the Environmental Social Impact Assessments (ESIAs) of the upstream and pipeline commenced in mid-2018. Extended injection and production testing also took place with results in line with expectations. Dynamic data from these tests has materially assisted with the development plan for the Foundation Stage. Key upstream components such as well count, well spacing and CPF design are now well defined.

In 2019, several critical tasks must be completed to reach a Final Investment Decision by year end. These tasks include completing commercial framework agreements with the Government of Kenya and finalising FEED studies in the first quarter of 2019 and concluding agreements over land title and water supply with the Government of Kenya and submitting both the upstream and the mid-stream ESIAs in the second quarter.

Early Oil Pilot Scheme (EOPS)

The transfer of stored crude oil from Turkana to Mombasa by road commenced on 3 June 2018. This milestone was marked by a ceremony attended by H.E. President Uhuru Kenyatta, H.E. Deputy President H.E. William Ruto, the Turkana County Governor, Turkana MPs as well as many other Government Ministers and officials. The first truck arrived at the refinery in Mombasa on 7 June 2018, where the oil is being stored for future export.

The trucks are currently transporting approximately 600 bopd and this is expected to increase to 2,000 bopd once the EOPS is fully operational in April 2019. So far, over 70,000 barrels of oil have been transported to Mombasa. A maiden lifting of Kenyan crude oil is expected in mid-2019. Tullow has begun to market Kenya’s low sulphur oil ahead of this first lifting with initial market reactions being very positive.

Uganda

Following meetings in January 2019 between the CEOs of both Tullow and Total and H.E. President Museveni of Uganda, Tullow has agreed the principles for Capital Gains Tax on its $900 million Uganda farm-down to CNOOC and Total. The Government and the JV Partners are now engaged in discussions to finalise an agreement reflecting this tax treatment that will enable completion of the farm-down to take place. Any Capital Gains Tax is expected to be phased and partly linked to project progress. At completion of the farm-down, Tullow anticipates receiving a cash payment of $100 million and a payment of the working capital completion adjustment and deferred consideration for the pre-completion period of $108 million. A further $50 million of cash consideration is due to be received when FID is taken on the development project.

The JV Partners continue to work towards reaching FID for the development project around mid-2019. During 2018, the upstream and pipeline FEED were completed in preparation for the award of Engineering, Procurement and Construction (EPC) contracts in 2019. Drilling and well construction designs and contracting activities are complete and contracts are ready to be awarded. ESIAs for both Tilenga and Kingfisher were submitted to the National Environmental Management Authority for review with approval expected in the first half of 2019. Land access activities have progressed with the active support of the Government in line with project requirements. In addition, critical transport infrastructure, including roads and an airport within the development area is being improved by the Government in support of the development.

Project financing for the pipeline is progressing well with the development of the financial model ongoing. In the first half of 2019, the JV Partners anticipate completing key commercial, technical and land agreements with the Governments of Uganda and Tanzania as well as the submission of an ESIA for the pipeline to both Governments.

NEW VENTURES

Ian Cloke, Executive Vice President for New Ventures, commented today:

> *“In 2019, Tullow will drill three wildcat wells in Guyana. These are high-potential, high-risk wells in the world’s newest oil hot spot and we are excited about the opportunity that our licences in Guyana offer. In addition, we continue to work up other drilling prospects in highly prospective areas across Africa and South America for drilling in 2020 and beyond.”*

Africa

Côte d’Ivoire

In Côte d’Ivoire, Tullow began its work programme across its new onshore blocks in April 2018 with a full tensor gravity gradiometry (FTG) survey covering 8,600 sq km. This survey was completed in May 2018 and the data is being used to optimise the location of a 2D seismic survey planned to commence in the third quarter of 2019. Tullow continues to reprocess 3D seismic data for the offshore Block CI-524 which sits alongside the maritime border with Ghana, next to Tullow’s operated TEN fields.

Tullow signed a farm-out agreement for a 30% interest in all seven onshore licences to Cairn Energy Plc. This farm-out is subject to obtaining Government approval and will leave Tullow with a 60% operated interest in each licence with most of the pre-drilling exploration costs carried.

Namibia

In September 2018, Tullow drilled the Cormorant-1 well offshore Namibia. The well encountered non-commercial hydrocarbons and was plugged and abandoned. Gas signatures, indicative of oil, were encountered in the overlying shale section, supporting the concept of a working oil system in the area. The combination of a simple well design, efficient operations and a farm-out in 2017 resulted in net expenditure on this well of less than $3 million. Data gained from the well, in combination with high quality 3D seismic data, will be used to evaluate the next steps for the Group's Namibian acreage in PEL-37. Separately, Tullow has decided to exit block PEL-30 in Namibia.

Mauritania

In 2018, a 9,300 sq km 3D seismic survey was completed over Block C18, in which Tullow holds a 15% non-operated stake. Tullow's share of the cost was carried under previous farm-down agreements. The data is currently being interpreted ahead of a drill or drop decision in April. In Block C3, in which Tullow holds a 100% operated stake, the Group has been interpreting the 3D seismic survey captured in 2017 to identify prospects for a potential 2020 well.

Zambia

In 2018, interpretation of a FTG survey and modelling of passive seismic data recorded in 2017 has indicated that this rift basin may be higher risk than originally anticipated. Tullow is therefore evaluating its next steps in Zambia.

The Comoros

Tullow announced on 29 November 2018 that it had agreed with Discover Exploration Ltd to farm into Blocks 35, 36 and 37, offshore the Union of the Comoros ("the Comoros") in the Indian Ocean. Following the completion of this transaction, which requires Government approval, Tullow will operate the three blocks and hold a working interest of 35%. The Blocks comprise an area of 16,063 sq km with a gross un-risked resource potential of up to 7 billion barrels of oil. A 3D seismic survey is planned for the third quarter of 2019.

South America

Guyana

Guyana will be the focus for Tullow's exploration drilling programme in 2019. Tullow plans to drill the Jethro prospect in the second quarter of 2019 as the first of two planned wells on the Orinduik block. Prospect selection amongst the JV Partners is ongoing for the second planned well on the Orinduik Block. The success of the neighbouring Hammerhead-1 well in August 2018, only seven kilometres from the Orinduik block boundary, has further de-risked this acreage. Tullow and its partners are in the final stages of contracting a Drillship for the Orinduik drilling programme.

The Carapa prospect will be tested on the Kanuku licence in the third quarter of 2019. In 2018, Tullow increased its equity share in the Kanuku licence, offshore Guyana, from 30% to 37.5% through a farm-in deal with Repsol.

Jamaica

Interpretation of a 2,200 sq km 3D seismic survey recorded in 2018 continues as Tullow matures prospects that can compete for capital for drilling in 2020.

Peru

In Peru, Tullow agreed the terms to acquire a 100% stake in offshore Blocks Z-64, Z-65, Z-66, Z-67 and Z-68 in early 2018. However, in May 2018, the Supreme Decrees, authorizing PeruPetro, the state regulator, to execute licence contracts for these blocks, were revoked by the Peruvian Government. Tullow was disappointed by this outcome as the Group complied with all the processes and procedures required under Peruvian law to agree new exploration licences.

Since the revocation, Tullow expressed its continued interest in the licences and has worked closely with PeruPetro towards execution of these licences. In January 2019, a new Supreme Decree was issued which detailed how oil exploration licences are to be awarded in Peru and included clear regulations around public consultation.

Separately, Tullow agreed to acquire a 35% interest in Block Z-38 through a farm-down from Karoon Gas Australia. This agreement also remains subject to Government approval. This acreage complements the Group's current position in South America and contains several attractive prospects and leads for potential drilling in 2020.

Suriname

In October, Tullow was awarded Block 62 in which it has a 100% operated interest. This block contains similar deep-water plays to Block 47. In addition, Tullow completed a farm-out of a 30% interest in the Block 47 licence to Pluspetrol for a carry on a future well. Work has continued maturing prospects in Block 47 for potential drilling in 2020. In Block 54, Tullow has continued to examine results from the Araku well ahead of any potential drilling.

Uruguay

Tullow has decided that it will not enter the next term of the Block 15 exploration licence with potential prospects being deemed too high risk. Tullow will exit the licence in March 2019.

Pakistan

In December 2018, Tullow agreed to sell its 30% interest in the Kohlu licence, Pakistan to OPL. Government approval is anticipated in the first half of 2019. This is Tullow's last remaining licence in Pakistan.

Finance review

Les Wood, Chief Financial Officer, commented today:

"Tullow has made excellent progress in 2018, significantly deleveraging the balance sheet and generating high levels of underlying free cash flow. The confidence we have in the performance of the business allowed us to establish a sustainable capital returns policy at the end of last year and our strong 2018 results have allowed us to announce a final dividend that will be payable in May 2019. We have developed a very firm foundation for growth over the last few years and I am confident that we can deliver significant shareholder returns in the years ahead."

Financial results summary	2018	2017
Working interest production volume (boepd)[1]	81,400	87,300
Sales volume (boepd)	74,200	82,200
Realised oil price ($/bbl)	68.5	58.3
Total revenue ($m)[2]	1,859	1,723
Gross profit ($m)	1,082	815
Underlying cash operating costs per boe ($/boe)[3]	10.0	11.1
Exploration costs written off ($m)	295	143
Impairment of property, plant and equipment, net ($m)	18	539
Operating profit ($m)	528	22
Profit/(loss) before tax ($m)	261	(286)
Profit/(loss) after tax ($m)	85	(175)
Basic profit/(loss) per share (cents)	6.1	(13.7)
Capital investment ($m)[3,4]	423	225
Adjusted EBITDAX ($m)[3]	1,600	1,346
Net debt ($m)[3]	3,060	3,471
Gearing (times)[3]	1.9	2.6
Free cash flow ($m)[3]	411	543

1. Including the impact of production-equivalent insurance payment barrels from the Jubilee field, Group working interest production was 90,000 boepd.
2. Total revenue does not include receipts for Tullow's corporate Business Interruption insurance of $188 million. This is included in Other Operating Income which is a component of Gross Profit.
3. Underlying cash operating costs per boe, capital investment, adjusted EBITDAX, net debt, gearing and free cash flow are non-IFRS measures and are explained later in this section.
4. Capital investment excludes Ugandan expenditure of $50 million in 2018 that will, subject to completion of the farm-down, be offset by either the working capital completion adjustment or deferred consideration.

Production and commodity prices

Working interest production averaged 81,400 boepd, a decrease of 7% for the year (2017: 87,300 boepd). Including the impact of production-equivalent insurance payments from the Jubilee field, working interest production averaged 90,000 boepd (2017: 94,700 boepd), a decrease of 5%. The decrease resulted from the impact of turret remediation work at Jubilee, and the cessation of production at higher cost non-operated assets. This was partially offset by strong production from the TEN fields and the remainder of the non-operated West Africa portfolio.

The Group's realised oil price after hedging was $68.5/bbl and $71.8/bbl before hedging (2017: $58.3/bbl and $54.2/bbl respectively). The increase in underlying oil prices reduced the net contribution of the realisation of hedges entered into by the Group to total revenue.

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

Underlying cash operating costs amounted to $327 million; $10.0/boe (2017: $386 million; $11.1/boe). Underlying cash operating costs were net of $46 million of insurance proceeds (2017: $51 million). The 10% decrease in unit cash operating costs was principally due to the impact of ongoing cost saving initiatives and the cessation of production from higher cost assets in the non-operated portfolio.

DD&A charges before impairment on production and development assets amounted to $568 million; $17.2/boe (2017: $574 million; $16.6/boe). A full year of amortisation of the TEN FPSO finance lease asset was recorded for the first time in 2018, as the asset was only recognised in the second half of 2017. This was offset by the impact of impairment recorded at the end of 2017.

The Group recognised a net impairment charge of $18 million in respect of 2018 (2017: $539 million). Impairments in Gabon were largely driven by the lower Dated Brent forward curve at 31 December 2018, whilst impairments in the UK related to increased decommissioning cost estimates. Impairment reversals were recorded in Côte d'Ivoire and Ghana as a result of reserves upgrades and improved cost forecasts, respectively.

During 2018, exploration costs write-offs were $295 million (2017: $143 million) and included $140 million for the Wawa and Akasa assets in Ghana, $75 million associated with capitalised interest on Uganda assets held for sale, and $25 million of New Ventures activity. The total exploration costs written off, net of tax, were $246 million (2017: $143 million).

Administrative expenses of $90 million (2017: $95 million) included an amount of $23 million (2017: $33 million) associated with share-based payment charges. In June 2015 the Group set a target to remove $500 million of cash costs from the business over a three-year period. During 2017 this target was increased to $650 million. The three-year period concluded on 30 June 2018, with the Group delivering $708 million of savings. The ongoing cost of running the business has reduced significantly and will continue to be a key area of focus.

Provision for onerous service contracts

Changes to provisions for onerous service contracts in 2018 resulted in an income statement charge in 2018 of $167 million (2017: credit of $1 million). This primarily resulted from the adverse litigation outcome related to the West Leo rig contract with Seadrill.

Derivative financial instruments

Tullow undertakes hedging activities as part of the ongoing management of its business risk to protect against volatility and to ensure the availability of cash flow for re-investment in capital programmes that are driving business growth.

At 31 December 2018, the Group's derivative instruments had a net positive fair value of $128 million (2017: negative $76 million), net of deferred premium.

2019 hedge position at 31 December 2018	Bopd	Bought put (floor)	Sold call	Bought call
Hedge structure				
Collars	22,244	$56.80	$81.68	–
Three-way collars (call spread)	29,488	$54.06	$74.60	$79.81
Straight puts	4,000	$69.24	–	–
Total/weighted average	**55,732**	**$56.24**	–	–

The 2020 hedging position at 31 December 2018 was 25,000 bopd hedged with an average floor price protected of $59.00/bbl.

Net financing costs

Net financing costs for the year were $270 million (2017: $310 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 2018 compared to 2017. Further, in 2017 a foreign exchange loss of $29 million was incurred in relation to the hedging of the proceeds from the Rights Issue. 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 finance lease assets, offset by interest earned on cash deposits and capitalised borrowing costs.

Taxation

The net tax expense of $175 million (2017: credit of $111 million) primarily relates to tax charges in respect of the Group's production activities in West Africa, as well as UK decommissioning assets, reduced by deferred tax credits associated with exploration write-offs, impairments and provisions for onerous service contracts.

The Group's statutory effective tax rate for 2018 is 67.2 per cent (2017: 37.0 per cent). After adjusting for non-recurring amounts related to exploration write-offs, disposals, impairments and provisions for onerous service contracts and their associated deferred tax benefit, the Group's adjusted tax rate is 40.7 per cent (2017: 23.8 per cent). The adjusted tax rate has increased due to changes in the geographical mix of profits, particularly the impact of increased profits from West Africa production taxed at higher rates, and lower tax credits due to reduced Norwegian exploration activities and the disposal of the Netherlands business during 2017.

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 costs write offs-occur.

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

The profit after tax for the year from continuing activities amounted to $85 million (2017: $175 million loss). Basic earnings per share was 6.1 cents (2017: 13.7 cents loss).

Reconciliation of net debt	$m
Year-end 2017 net debt	**3,471**
Sales revenue	(1,859)
Other operating income – lost production insurance proceeds	(188)
Operating costs	327
Operating expenses	432
Cash flow from operations	**(1,288)**
Movement in working capital	(19)
Tax paid	103
Purchases of intangible exploration and evaluation assets and property, plant, and equipment	441
Other investing activities	(13)
Other financing activities	367
Foreign exchange gain on cash	(2)
Year-end 2018 net debt	**3,060**

Capital investment

2018 capital investment (net of Uganda expenditure which will be repaid from either the working capital completion adjustment or deferred consideration post the completion of the Uganda farm-down) amounted to $423 million (2017: $225 million) with $353 million invested in development activities and $70 million invested in Exploration and Appraisal activities. More than 60% of the total was invested in Kenya and Ghana and over 95% was invested in Africa.

Capital expenditure will continue to be carefully controlled during 2019. The Group's 2019 capital expenditure is expected to total approximately $570 million. This total excludes c.$170 million of forecast Uganda expenditure which will be repaid from either the working capital completion adjustment or deferred consideration post the completion of the Uganda farm-down, which is expected in the first half of 2019. The capital investment total comprises Ghana capex of c.$250 million, West Africa non-operated capex of c.$90 million, Kenya pre-development expenditure of c.$70 million, Uganda post-completion Tullow costs of c.$10m, and Exploration and Appraisal expenditure of c.$140 million.

At completion of the Uganda farm-down, Tullow is also due to receive $100 million cash consideration along with re-imbursement of 2017 and 2018 capex of c.$108 million. A further $50 million cash consideration is due to be received when FID is taken on the development project.

Borrowings

On 23 March 2018, Tullow completed its offering of $800 million of senior notes, due in 2025. The offering was significantly oversubscribed and increased from the initial offering of $650 million. Proceeds were used to redeem, in full, senior notes due in 2020 and repay drawings on the Reserve Based Lending facility. The senior notes offering further extended Tullow's debt maturities, with no scheduled debt repayments until 2021. On 4 April 2018, commitments under Tullow's Revolving Corporate Facility (RCF) amortised in line with the schedule to $500 million, on 18 April 2018 Tullow voluntarily cancelled a further $150 million of commitments under the facility, and in November 2018, given the strength of the balance sheet, the Board decided to cancel the Group's undrawn $350 million RCF, four months before maturity, to realise cost savings from reduced commitment fees. Following the cancellation of this facility, liquidity headroom of unutilised debt capacity and free cash were $1 billion at the end of 2018, maintaining flexibility for future opportunities.

As a result of the implementation of IFRS 9: Financial instruments, the Group's opening non-current borrowings on 1 January 2018 increased by $111 million. Refer to note 1 for further details.

Credit Ratings

Tullow maintains corporate credit ratings with Standard & Poor's and Moody's Investors Service. During the year, Standard & Poor's upgraded Tullow's corporate credit rating to B+ from B, and assigned a positive outlook; in addition, Standard & Poor's raised the rating of Tullow's corporate bonds to B+, in line with the corporate credit rating. Moody's Investors Service upgraded Tullow's Corporate Family Rating to B1 from B2, and consequently the rating of Tullow's corporate bonds was raised to B3 from Caa1.

Liquidity risk management and going concern

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 and different production rates from the Group's producing assets. The Group had $1 billion liquidity headroom of unutilised debt capacity and free cash at the end of 2018. 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 12 months from the date of approval of the 2018 Annual Report and Accounts.

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 continue to adopt the going concern basis of accounting in preparing the annual Financial Statements.

Brexit

It is the view of the Board that, given the Group's focus on Africa and South America, Tullow's business, assets and operations will not be materially affected by Brexit. Tullow also derives its income from crude oil, a globally-traded commodity which is priced in US dollars.

Nevertheless, Tullow employs a number of EU nationals in the UK and the Board is concerned about the uncertainty that a No Deal Brexit would cause these much-valued members of staff. To help address this concern, Tullow has established a Brexit Focus Group to share information with affected employees and ensure they are up to date with the latest developments.

The Board also recognises that a No Deal Brexit could cause significant regulatory, legal and financial uncertainty with regard to our decommissioning programme in the UK North Sea. Operators would have to be carefully guided by the Department for Business, Energy and Industrial Strategy as to exactly how decommissioning programmes should be executed and what tariffs or fees, if any, should be applied to non-UK service providers.

Events since 31 December 2018

There has not been any event since 31 December 2018 that has resulted in a material impact on the year end results.

Non-IFRS 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, 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.

	2018 $m	2017 $m
Additions to property, plant and equipment	268.1	887.7
Additions to intangible exploration and evaluation assets	230.4	319.0
Less		
Decommissioning asset additions	(42.7)	(33.6)
Finance lease asset additions	(3.8)	837.6
Capitalised share-based payment charge	1.3	0.3
Capitalised finance costs	65.3	66.5
Additions to administrative assets	6.6	7.0
Norwegian tax refund	0.4	2.1
Uganda capital investment	50.5	57.5
Other non-cash capital expenditure	(2.3)	44.7
Capital investment	**423.2**	**224.6**
Movement in working capital	(40.2)	16.3
Additions to administrative assets	6.6	7.0
Norwegian tax refund	0.4	2.1
Uganda capital investment	50.5	57.5
Cash capital expenditure per the cash flow statement	**440.5**	**307.5**

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. The Group's definition of net debt does not include the Group's finance leases as the Group's focus is the management of cash borrowings and a finance lease is viewed as deferred capital investment. The value of the Group's finance lease liabilities as at 31 December 2018 was $221.2 million current and $1,191.0 million non-current; it should be noted that these balances are recorded gross for operated assets and are therefore not representative of the Group's net exposure under these contracts.

	2018 $m	2017 $m
Non-current borrowings	3,219.1	3,606.4
Non-cash adjustments	20.9	148.6
Less cash and cash equivalents	(179.8)	(284.0)
Net debt	**3,060.2**	**3,471.0**

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 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. Adjusted EBITDAX therefore excludes interest on obligations under finance leases of $101.5 million, and interest income on amounts due from Joint Venture partners for finance leases of $52.7 million, as in assessing business performance, management considers lease payments in substance to represent deferred capital expenditure. Had these been included in the calculation of Adjusted EBITDAX, calculated gearing would have been 2.0 times.

	2018 $m	2017 $m
Profit/(loss) from continuing activities	85.4	(175.3)
Less		
Income tax expense/(credit)	175.1	(110.6)
Finance costs	328.7	351.7
Finance revenue	(58.4)	(42.0)
Gain on hedging instruments	(2.4)	(1.4)
Depreciation, depletion and amortisation	584.1	592.2
Share-based payment charge	24.9	33.9
Restructuring costs	3.4	14.5
(Gain)/loss on disposal	(21.3)	1.6
Exploration costs written off	295.2	143.4
Impairment of property, plant and equipment, net	18.2	539.1
Provision for onerous service contracts, net	167.4	(1.0)
Adjusted EBITDAX	**1,600.3**	**1,346.1**
Net debt	**3,060.2**	**3,471.0**
Gearing (times)	**1.9**	**2.6**

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.

	2018 $m	2017 $m
Cost of sales	966.0	1,069.3
Less		
Operating lease expense for the TEN FPSO	–	62.5
Depletion and amortisation of oil and gas assets	567.7	574.3
Underlift, overlift and oil stock movements	40.7	(2.3)
Share-based payment charge included in cost of sales	1.0	1.1
Other cost of sales	29.6	47.5
Underlying cash operating costs	**327.0**	**386.2**
Production (MMboe)	32.9	34.7
Underlying cash operating costs per boe ($/boe)	**10.0**	**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 used in investing activities, less debt arrangement fees, repayment of obligations under finance leases, finance costs paid, foreign exchange gain, and distribution to non-controlling interests.

	2018 $m	2017 $m
Net cash from operating activities	1,204.0	1,222.9
Net cash used in investing activities	(427.7)	(296.4)
Debt arrangement fees	(15.0)	(56.4)
Repayment of obligations under finance leases	(117.4)	(62.6)
Finance costs paid	(234.5)	(265.4)
Foreign exchange gain	1.5	3.5
Distribution to non-controlling interests	–	(3.0)
Free cash flow	**410.9**	**542.6**

Group income statement

Year ended 31 December 2018

	Notes	2018 $m	2017 Restated[1] $m
Continuing activities			
Sales revenue		1,859.2	1,722.5
Other operating income – lost production insurance proceeds	7	188.4	162.1
Cost of sales	5	(966.0)	(1,069.3)
Gross profit		1,081.6	815.3
Administrative expenses	5	(90.3)	(95.3)
Restructuring costs	5	(3.4)	(14.5)
Gain/(loss) on disposal		21.3	(1.6)
Exploration costs written off	9	(295.2)	(143.4)
Impairment of property, plant and equipment, net	10	(18.2)	(539.1)
Provision for onerous service contracts, net		(167.4)	1.0
Operating profit		528.4	22.4
Gain on hedging instruments		2.4	1.4
Finance revenue	6	58.4	42.0
Finance costs	6	(328.7)	(351.7)
Profit/(loss) from continuing activities before tax		260.5	(285.9)
Income tax (expense)/credit	8	(175.1)	110.6
Profit/(loss) for the year from continuing activities		85.4	(175.3)
Attributable to:			
Owners of the Company		84.8	(176.3)
Non-controlling interest		0.6	1.0
		85.4	(175.3)
Profit/(loss) per ordinary share from continuing activities		¢	¢
Basic	2	6.1	(13.7)
Diluted	2	5.9	(13.7)

Group statement of comprehensive income and expense

Year ended 31 December 2018

	2018 $m	2017 Restated[1] $m
Profit/(loss) for the year	85.4	(175.3)
Items that may be reclassified to the income statement in subsequent periods		
Cash flow hedges		
Gain arising in the year	100.7	6.7
Gain/(loss) arising in the year – time value	16.2	(64.7)
Reclassification adjustments for items included in profit/(loss) on realisation	32.7	(137.5)
Reclassification adjustments for items included in profit/(loss) on realisation – time value	52.7	51.5
Exchange differences on translation of foreign operations	(15.4)	9.0
Other comprehensive profit/(loss)	186.9	(135.0)
Tax relating to components of other comprehensive profit/(loss)	–	24.3
Net other comprehensive profit/(loss) for the year	186.9	(110.7)
Total comprehensive income/(expense) for the year	272.3	(286.0)
Attributable to:		
Owners of the Company	271.7	(287.0)
Non-controlling interest	0.6	1.0
	272.3	(286.0)

[1] 2017 figures restated in relation to the implementation of IFRS 9 Financial Instruments. Refer to note 1.

Group balance sheet

As at 31 December 2018

	Notes	2018 $m	2017 Restated[1] $m
ASSETS			
Non-current assets			
Intangible exploration and evaluation assets	9	1,898.6	1,933.4
Property, plant and equipment	10	4,916.4	5,254.7
Investments		–	1.0
Other non-current assets	11	696.4	789.8
Derivative financial instruments		51.2	0.8
Deferred tax assets		649.4	724.5
		8,212.0	8,704.2
Current assets			
Inventories		134.8	168.0
Trade receivables		159.4	171.4
Other current assets	11	969.0	768.3
Current tax assets		60.5	57.7
Derivative financial instruments		79.7	1.8
Cash and cash equivalents		179.8	284.0
Assets classified as held for sale	12	840.2	873.1
		2,423.4	2,324.3
Total assets		10,635.4	11,028.5
LIABILITIES			
Current liabilities			
Trade and other payables	13	(1,204.3)	(1,025.6)
Provisions	14	(198.5)	(230.8)
Current tax liabilities		(83.0)	(45.0)
Derivative financial instruments		(2.7)	(53.1)
		(1,488.5)	(1,354.5)
Non-current liabilities			
Trade and other payables	13	(1,282.3)	(1,422.6)
Borrowings		(3,219.1)	(3,606.4)
Provisions	14	(677.0)	(801.6)
Deferred tax liabilities		(1,075.3)	(1,101.2)
Derivative financial instruments		–	(25.8)
		(6,253.7)	(6,957.6)
Total liabilities		(7,742.2)	(8,312.1)
Net assets		2,893.2	2,716.4
EQUITY			
Called up share capital		209.1	208.2
Share premium		1,344.2	1,326.8
Equity component of convertible bonds		48.4	48.4
Foreign currency translation reserve		(238.6)	(223.2)
Hedge reserve		130.8	(2.6)
Hedge reserve – time value		(4.9)	(73.8)
Other reserves		755.2	740.9
Retained earnings		649.0	681.3
Equity attributable to equity holders of the Company		2,893.2	2,706.0
Non-controlling interest		–	10.4
Total equity		2,893.2	2,716.4

[1] 2017 figures restated in relation to the implementation of IFRS 9 Financial Instruments. Refer to note 1.

Group statement of changes in equity

Year ended 31 December 2018

	Called up 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[2] $m	Other reserves[3] $m	Retained earnings $m	Total $m	Non-controlling interest $m	Total Equity $m
At 1 January 2017	147.5	619.3	48.4	(232.2)	128.2	–	740.9	778.0	2,230.1	12.4	2,242.5
Adjustment of adoption of IFRS 9, net of tax[4]	–	–	–	–	–	(60.6)	–	60.6	–	–	–
Loss for the year	–	–	–	–	–	–	–	(176.3)	(176.3)	1.0	(175.3)
Hedges, net of tax	–	–	–	–	(130.8)	(13.2)	–	–	(144.0)	–	(144.0)
Currency translation adjustments	–	–	–	9.0	–	–	–	–	9.0	–	9.0
Issue of shares – Rights Issue	60.0	693.8	–	–	–	–	–	–	753.8	–	753.8
Issue of employee share options	0.7	13.7	–	–	–	–	–	–	14.4	–	14.4
Vesting of PSP shares	–	–	–	–	–	–	–	(15.2)	(15.2)	–	(15.2)
Share-based payment charges	–	–	–	–	–	–	–	34.2	34.2	–	34.2
Distribution to non-controlling interests	–	–	–	–	–	–	–	–	–	(3.0)	(3.0)
At 1 January 2018	208.2	1,326.8	48.4	(223.2)	(2.6)	(73.8)	740.9	681.3	2,706.0	10.4	2,716.4
Adjustment on adoption of IFRS 9, net of tax[4]	–	–	–	–	–	–	–	(110.8)	(110.8)	–	(110.8)
Profit for the year	–	–	–	–	–	–	–	84.8	84.8	0.6	85.4
Hedges, net of tax	–	–	–	–	133.4	68.9	–	–	202.3	–	202.3
Currency translation adjustments	–	–	–	(15.4)	–	–	–	–	(15.4)	–	(15.4)
Issues of employee share options	0.9	17.4	–	–	–	–	–	–	18.3	–	18.3
Vesting of employee share options	–	–	–	–	–	–	–	(18.2)	(18.2)	–	(18.2)
Transfers	–	–	–	–	–	–	14.3	(14.3)	–	–	–
Share-based payment charges	–	–	–	–	–	–	–	26.2	26.2	–	26.2
Acquisition of non-controlling interests	–	–	–	–	–	–	–	–	–	(11.0)	(11.0)
At 31 December 2018	209.1	1,344.2	48.4	(238.6)	130.8	(4.9)	755.2	649.0	2,893.2	–	2,893.2

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. *Other reserves include the merger reserve. The value associated with the treasury shares reserve, disclosed in the previous year, has been represented as part of retained earnings, consistent with the share based payment reserve. At 31 December 2018 the Group did not hold any shares in a Tullow Oil Employee Trust to satisfy awards held under the Group's share incentive plans.*
4. *For further details of the adjustment on adoption of IFRS 9, refer to note 1. Note that the figures for 1 January 2017 to 1 January 2018 have been restated in relation to the adoption of IFRS 9.*

Group cash flow statement

Year ended 31 December 2018

	Notes	2018 $m	2017 Restated[1] $m
Cash flows from operating activities			
Profit/(loss) before taxation		260.5	(285.9)
Adjustments for:			
Depreciation, depletion and amortisation		584.1	592.2
(Gain)/loss on disposal		(21.3)	1.6
Exploration costs written off	9	295.2	143.4
Impairment of property, plant and equipment, net	10	18.2	541.1
Provision for onerous service contracts, net	14	167.4	(1.0)
Payments under onerous service contracts	14	(208.6)	–
Decommissioning expenditure	14	(99.1)	(25.7)
Share-based payment charge		23.8	33.9
Gain on hedging instruments		(2.4)	(1.4)
Finance revenue	6	(58.4)	(42.0)
Finance costs	6	328.7	351.7
Operating cash flow before working capital movements		1,288.1	1,307.9
(Increase)/decrease in trade and other receivables		(100.2)	122.0
Decrease/(increase) in inventories		32.5	(20.8)
Increase/(decrease) in trade payables		86.9	(251.4)
Cash flows from operating activities		1,307.3	1,157.7
Income taxes (paid)/received		(103.3)	65.2
Net cash from operating activities		1,204.0	1,222.9
Cash flows from investing activities			
Proceeds from disposals		9.9	8.0
Purchase of intangible exploration and evaluation assets		(202.1)	(189.7)
Purchase of property, plant and equipment		(238.4)	(117.8)
Interest received		2.9	3.1
Net cash used in investing activities		(427.7)	(296.4)
Cash flows from financing activities			
Net proceeds from issue of share capital		–	768.1
Debt arrangement fees		(15.0)	(56.4)
Repayment of bank loans		(1,755.1)	(1,613.6)
Drawdown of bank loans		1,240.0	305.0
Repayment of obligations under finance leases		(117.4)	(62.6)
Finance costs paid		(234.5)	(265.4)
Distribution to non-controlling interests		–	(3.0)
Net cash used in financing activities		(882.0)	(927.9)
Net decrease in cash and cash equivalents		(105.7)	(1.4)
Cash and cash equivalents at beginning of year		284.0	281.9
Foreign exchange gain		1.5	3.5
Cash and cash equivalents at end of year		179.8	284.0

[1] 2017 figures restated in relation to the implementation of IFRS 9 Financial Instruments. Refer to note 1.

Notes to the preliminary financial statements

Year ended 31 December 2018

1. Basis of Accounting 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 March 2019.

The financial information for the year ended 31 December 2018 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 2017 have been delivered to the Registrar of Companies and those for 2018 will be delivered following the Company's annual general meeting. The auditor has reported on these accounts; their reports were unqualified, did not include a reference to any matters to which the auditor drew attention by way of emphasis of matter and did not contain a statement under section 498 (2) or (3) of the Companies Act 2006.

The accounting policies applied are consistent with those adopted and disclosed in the Group's financial statements for the year ended 31 December 2017. 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 2018, however these have not had a material impact on the accounting policies, methods of computation or presentation applied by the Group, except for IFRS 9 Financial Instruments. The classification and measurement of financial liabilities is materially consistent with that required by IAS 39 Financial Instruments: Recognition and Measurement with the exception of the treatment of modification or exchange of financial liabilities which do not result in derecognition. The Group has identified that retrospective application of IFRS 9 has increased the carrying value of the Reserves Based Lending credit facility by $110.8 million and resulted in the need to record a modification loss due to the refinancing of the facility in November 2017. The implementation reduced retained earnings on 1 January 2018. This will lower the finance costs recognised over the remaining life of the facility compared to the treatment under IAS 39. No other material impact as a result of IFRS 9's classification and measurement requirements has been identified. The Group adopted the hedge accounting requirements of IFRS 9 Financial Instruments effective 1 January 2018. The new hedge accounting rules will align the hedge accounting treatments more closely with the Group's risk management strategy, and address previous inconsistencies and weakness in the hedge accounting model in IAS 39. The Group has identified a change in the treatment of the 'cost of hedging' of options on adoption of IFRS 9, specifically with respect to the fair value movement of time value. The fair value movement of time value, to the extent which it relates to the hedged item, has been presented as a separate component in the statement of comprehensive income and expenses. The 'gain/loss on hedging instruments' line in the Group's income statement now solely captures ineffectiveness in the underlying hedges. This requirement has been applied retrospectively, as required, on adoption of IFRS 9. As a result of these changes, certain figures for 2017 have been labelled as 'restated' in the 2018 year end results statements.

There are also a number of amendments to accounting standards and new interpretations issued by the International Accounting Standards Board which will be applicable from 1 January 2019 onwards. These are not expected to have a material impact on the accounting policies, methods of computation or presentation applied by the Group, except for IFRS 16 Leases.

Further details on new International Financial Reporting Standards adopted and yet to be adopted will be disclosed in the 2018 Annual Report and Accounts.

2. Profit/(loss) per share

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

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

3. 2018 Annual Report and Accounts

The 2018 Annual Report and Accounts will be mailed in March 2019 only to those shareholders who have elected to receive it. Otherwise, shareholders will be notified that the Annual Report and Accounts are available on the Group's website (www.tullowoil.com). Copies of the Annual Report and Accounts will also be available from the Company's registered office at Building 9, Chiswick Park, 566 Chiswick High Road, London, W4 5XT.

4. Segmental reporting

The information reported to the Group's Chief Executive Officer for the purposes of capital allocation and assessment of segment performance is focused on three Business Delivery Teams, West Africa (including non-operated European assets), East Africa and New Ventures. Therefore the Group's reportable segments under IFRS 8 are West Africa; East Africa; and New Ventures. 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 2018 and 31 December 2017.

	West Africa $m	East Africa $m	New Ventures $m	Unallocated $m	Total $m
2018					
Sales revenue by origin	1,859.2	–	–	–	1,859.2
Other operating income – lost production insurance proceeds	–	–	–	188.4	188.4
Segment result	528.0	(74.5)	(100.7)	248.0	600.8
Gain on disposal					21.3
Unallocated corporate expenses					(93.7)
Operating profit					528.4
Gain on hedging instruments					2.4
Finance revenue					58.4
Finance costs					(328.7)
Profit before tax					260.5
Income tax expense					(175.1)
Profit after tax					85.4
Total assets	7,618.9	2,662.0	280.8	73.7	10,635.4
Total liabilities	(4,252.7)	(141.8)	(96.9)	(3,250.8)	(7,742.2)
Other segment information					
Capital expenditure:					
Property, plant and equipment	257.1	1.4	4.3	5.3	268.1
Intangible exploration and evaluation assets	2.1	168.3	60.0	–	230.4
Depreciation, depletion and amortisation	(569.2)	(0.2)	–	(14.7)	(584.1)
Impairment of property, plant and equipment, net	(18.2)	–	–	–	(18.2)
Exploration costs written off	(139.9)	(74.5)	(80.8)	–	(295.2)

4. Segmental reporting contd.

	West Africa $m	East Africa $m	New Ventures $m	Unallocated $m	Total $m
2017 (Restated)					
Sales revenue by origin	1,722.5	–	–	–	1,722.5
Other operating income – lost production insurance proceeds	–	–	–	162.1	162.1
Segment result	86.9	(2.2)	(133.9)	183.0	133.8
Loss on disposal					(1.6)
Unallocated corporate expenses					(109.8)
Operating profit					22.4
Gain on hedging instruments					1.4
Finance revenue					42.0
Finance costs					(351.7)
Loss before tax					(285.9)
Income tax credit					110.6
Loss after tax					(175.3)
Total assets	7,857.2	2,585.2	306.0	280.1	11,028.5
Total liabilities	(4,295.6)	(169.2)	(97.1)	(3,750.2)	(8,312.1)
Other segment information					
Capital expenditure:					
Property, plant and equipment	43.1	1.1	0.3	5.6	50.1
Intangible exploration and evaluation assets	5.5	257.5	56.0	–	319.0
Depreciation, depletion and amortisation	(577.1)	(0.5)	–	(14.6)	(592.2)
Impairment of property, plant and equipment, net	(539.1)	–	–	–	(539.1)
Exploration costs written off	(6.9)	(2.3)	(134.2)	–	(143.4)

Unallocated expenditure and net liabilities include amounts of a corporate nature and not specifically attributable to a reportable segment. The liabilities comprise the Group's external debt and other non-attributable corporate liabilities.

5. Other costs

	Notes	2018 $m	2017 $m
Cost of sales			
Operating costs		327.0	386.2
Operating lease expense for the TEN FPSO		–	62.5
Depletion and amortisation of oil and gas assets	10	567.7	574.3
Underlift, overlift and oil stock movements		40.7	(2.3)
Share-based payment charge included in cost of sales		1.0	1.1
Other cost of sales		29.6	47.5
Total cost of sales		966.0	1,069.3
Administrative expenses			
Share-based payment charge included in administrative expenses		22.8	32.8
Depreciation of other fixed assets	10	16.4	17.9
Relocation costs		(1.3)	1.6
Other administrative costs		52.4	43.0
Total administrative expenses		90.3	95.3
Restructuring costs		3.4	14.5

6. Net financing costs

	2018 $m	2017 $m
Interest on bank overdrafts and borrowings	276.0	290.7
Interest on obligations under finance leases	101.5	46.1
Total borrowing costs	377.5	336.8
Less amounts included in the cost of qualifying assets	(65.3)	(66.5)
	312.2	270.3
Finance and arrangement fees	(0.6)	2.8
Other interest expense	2.7	1.8
Foreign exchange losses	–	57.1
Unwinding of discount on decommissioning provisions	14.4	19.7
Total finance costs	328.7	351.7
Interest income on amounts due from joint venture partners for finance leases	(52.7)	(21.0)
Other finance revenue	(5.7)	(21.0)
Total finance revenue	(58.4)	(42.0)
Net financing costs	270.3	309.7

7. Insurance proceeds

During 2018 the Group continued to issue insurance claims in respect of the Jubilee turret remediation project. Insurance proceeds of $310.8 million were recorded in the year ended 31 December 2018 (2017: $220.9 million). Proceeds related to lost production under the Business Interruption insurance policy of $188.4 million (2017 $162.1 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 $45.6 million (2017: $50.9 million) were recorded within the operating costs line of cost of sales (see note 5). Proceeds related to compensation for capital costs under the Hull and Machinery insurance policy of $76.9 million (2017: $7.9 million) were recorded within additions to property, plant and equipment (see note 10).

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

a. Analysis of tax expense/(credit) for the year

	2018 $m	2017 $m
Current tax		
UK corporation tax	(37.3)	30.1
Foreign tax	171.7	6.2
Total corporate tax	134.4	36.3
UK petroleum revenue tax	–	(2.1)
Total current tax	134.4	34.2
Deferred tax		
UK corporation tax	33.9	(8.7)
Foreign tax	(11.3)	(114.6)
Total deferred corporate tax	22.6	(123.3)
Deferred UK petroleum revenue tax	18.1	(21.5)
Total deferred tax	40.7	(144.8)
Total tax expense/(credit)	175.1	(110.6)

8. Taxation on profit/(loss) on ordinary activities contd.

b. Factors affecting tax expense/(credit) for the year

The tax rate applied to profit on ordinary activities in preparing the reconciliation below is the UK corporation tax rate applicable to the Group's non-upstream UK profits. The difference between the total tax expense/(credit) shown above and the amount calculated by applying the standard rate of UK corporation tax applicable to UK profits of 19% (2017: 19%) to the profit/(loss) before tax is as follows:

	2018 $m	2017 $m
Group profit/(loss) on ordinary activities before tax	260.5	(285.9)
Tax on Group profit/(loss) on ordinary activities at the standard UK corporation tax rate of 19% (2017: 19%)	49.5	(54.3)
Effects of:		
Non-deductible exploration expenditure	20.8	21.6
Fair value movements on derivatives	32.0	–
Other non-deductible expenses	12.8	10.1
Derecognition of deferred tax previously recognised	37.3	–
Recognition of deferred tax previously unrecognised	–	(21.5)
Utilisation of tax losses not previously recognised	(10.6)	(0.3)
Net losses not recognized	7.7	18.4
Adjustment relating to prior years	1.0	1.9
Adjustments to deferred tax relating to change in tax rates	(2.1)	12.6
Higher rate of taxation on Norway losses	(10.0)	13.1
Other tax rates applicable outside the UK and Norway	52.4	(88.0)
PSC income not subject to corporation tax	(8.8)	(15.4)
Tax incentives for investment	–	(2.8)
Other income not subject to corporation tax	(6.9)	(6.0)
Group total tax expense/(credit) for the year	175.1	(110.6)

The Finance Act 2016 further reduced the main rate of UK corporation tax applicable to all companies subject to corporation tax, except for those within the oil and gas ring fence, to 19% from 1 April 2017 and 17% from 1 April 2020. These changes were substantively enacted on 6 September 2016 and hence the effect of the change on the deferred tax balances has been included, depending upon when deferred tax is expected to reverse.

The Group's profit before taxation will continue to arise in jurisdictions where the effective rate of taxation differs from that in the UK, such as Ghana (35%), Gabon (50%), and Equatorial Guinea (35%). Furthermore, unsuccessful exploration expenditure is often incurred in jurisdictions where the Group has no taxable profits, such that no related tax benefit arises. Accordingly, the Group's tax charge will continue to vary according to the jurisdictions in which pre-tax profits and exploration costs written off arise.

The Group has tax losses of $3,581.3 million (2017: $3,642.0 million) that are available for offset against future taxable profits in the companies in which the losses arose. Deferred tax assets have not been recognised in respect of these losses as they may not be used to offset taxable profits elsewhere in the Group due to uncertainty of recovery.

The Group has recognised deferred tax assets of $527.5 million (2017: $530.0 million) in relation to tax losses only to the extent of anticipated future taxable income or gains in relevant jurisdictions.

No deferred tax liability is recognised on temporary differences of $7.8 million (2017: $7.9 million) relating to unremitted earnings of overseas subsidiaries as the Group is able to control the timing of the reversal of these temporary differences and it is probable that they will not reverse in the foreseeable future.

Tax relating to components of other comprehensive income

During 2018 $nil (2017: $24.3 million) of tax has been recognised through other comprehensive income of which $nil (2017: $24.9 million) is current and $nil (2017: $0.6 million) is deferred tax relating to all debit (2017: debit) on cash flow hedges arising in the year.

Current tax assets

As at 31 December 2018, current tax assets were $60.5 million (2017: $57.7 million) of which $58.7 million relates to the UK (2017: $44.6 million).

9. Intangible exploration and evaluation assets

	2018 $m	2017 $m
At 1 January	1,933.4	2,025.8
Additions	230.4	319.0
Disposals	(4.0)	(40.0)
Amounts written off	(295.2)	(143.4)
Transfer to assets held for sale	32.2	(43.4)
Transfer to property, plant and equipment	–	(188.7)
Currency translation adjustments	1.8	4.1
At 31 December	1,898.6	1,933.4

Included within 2018 additions is $65.3 million of capitalised interest (2017: $66.5 million) related to Uganda. The Group only capitalises interest in respect of intangible exploration and evaluation assets where it is considered that development is ongoing.

Transfers to property, plant, and equipment in 2017 related to the Greater Jubilee Full Field Development plan of development approval and the cost associated with the Mahogany and Teak discoveries.

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

Country	CGU	Rationale for 2018 write-off	2018 Pre-tax write-off /(reversal) $m	2018 Post-tax write-off /(reversal) $m	2018 Remaining recoverable amount $m
Ghana	Wawa	g	42.7	27.8	–
Ghana	Akasa	g	97.1	63.1	–
Mauritania	Block C18	b,c	8.5	8.5	–
Namibia	PEL 37	a	13.0	13.0	26.9
Namibia	PEL 30	a	9.0	9.0	–
Pakistan	Various	b	1.1	1.1	–
Suriname	Block 54	b,c	3.6	3.6	–
Uganda	Assets held for sale	e	74.5	74.5	N/a
Uruguay	Country	d	16.3	16.3	–
Zambia	Country	d	4.5	4.5	–
Other	Various	b	0.3	0.3	–
New Ventures	Various	f	24.6	24.6	–
Total write-off			295.2	246.3	

a. Current year unsuccessful exploration results or assessments
b. Current year expenditure and actualisation of accruals associated with CGUs previously written off
c. Licence relinquishments or expiry
d. Country exit
e. Revision of value based on fair value calculation
f. New Ventures expenditure is written off as incurred
g. Exploration and evaluation assets associated with Wawa and Akasa in Ghana were written off during 2018 as substantive expenditure on further exploration work on these licences is not planned in the near-term.

10. Property, plant and equipment

	2018 Oil and gas assets $m	2018 Other fixed assets $m	2018 Total $m	2017 Oil and gas assets $m	2017 Other fixed assets $m	2017 Total $m
Cost						
At 1 January	11,592.6	279.7	11,872.3	10,772.5	251.9	11,024.4
Additions	261.5	6.6	268.1	880.7	7.0	887.7
Disposals	–	(0.7)	(0.7)	(362.6)	(1.6)	(364.2)
Transfer from intangible assets	–	–	–	188.7	–	188.7
Currency translation adjustments	(60.1)	(14.6)	(74.7)	113.3	22.4	135.7
At 31 December	11,794.0	271.0	12,065.0	11,592.6	279.7	11,872.3
Depreciation, depletion and amortisation						
At 1 January	(6,425.3)	(192.3)	(6,617.6)	(5,500.8)	(160.7)	(5,661.5)
Charge for the year	(567.7)	(16.4)	(584.1)	(574.3)	(17.9)	(592.2)
Impairment loss	(55.8)	–	(55.8)	(584.5)	–	(584.5)
Reversal of impairment loss	37.6	–	37.6	43.4	–	43.4
Disposal	–	0.7	0.7	300.0	1.7	301.7
Currency translation adjustments	60.1	10.5	70.6	(109.1)	(15.4)	(124.5)
At 31 December	(6,951.1)	(197.5)	(7,148.6)	(6,425.3)	(192.3)	(6,617.6)
Net book value at 31 December	4,842.9	73.5	4,916.4	5,167.3	87.4	5,254.7

The carrying amount of the Group's oil and gas assets includes an amount of $685.2 million (2017: $816.7 million) in respect of assets held under finance leases. 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. The 2018 income statement impairment charge includes $nil of insurance proceeds (2017: $2.0 million).

	Trigger for 2018 impairment/(reversal)	2018 Impairment/(reversal) $m	Pre-tax discount rate assumption
Limande and Turnix CGU (Gabon)	a	14.2	13%
Echira, Niungo, and Igongo CGU (Gabon)	a	2.9	15%
Tchatamba (Gabon)	a	(1.4)	13%
Oba and Middle Oba (Gabon)	a	2.8	13%
Espoir (Côte d'Ivoire)	c	(22.9)	10%
TEN (Ghana)	e	(13.3)	10%
UK "CGU"[d]	b	35.9	n/a
Impairment		18.2	

a. Decrease to short-term price assumptions (Dated Brent forward curve)
b. Change to decommissioning estimate.
c. Revision of value based on revisions to reserves
d. The fields in the UK are grouped into one CGU as all fields within those countries share critical gas infrastructure.
e. Revisions of cost profiles

During 2018 and 2017 the Group applied the following nominal oil price assumptions for impairment tests:

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 onwards
2018	Forward curve	Forward curve	$66/bbl	$68/bbl	$75/bbl	$75/bbl inflated by 2%
2017	Forward curve	Forward curve	$59/bbl	$66/bbl	$68/bbl	$75/bbl inflated by 2%

All impairment assessments are prepared on a value-in-use basis using discounted future cash flows based on 2P reserves profiles.

11. Other assets

	2018 $m	2017 $m
Non-current		
Amounts due from joint venture partners	614.9	731.7
Uganda VAT recoverable	33.1	34.9
Other non-current assets	48.4	23.2
	696.4	789.8
Current		
Amounts due from joint venture partners	670.8	567.8
Underlifts	22.9	37.1
Prepayments	73.4	38.2
VAT recoverable	3.8	5.4
Other current assets	198.1	119.8
	969.0	768.3

Other current assets have increased due to the increase in the amount of funds due from insurers.

12. Assets held for sale

In 2017, Tullow announced that it had agreed a substantial farm-down of its assets in Uganda. Under the Sale and Purchase Agreement, Tullow has agreed to transfer 21.57% of its 33.33% Uganda interests for a total consideration of $900 million. Upon completion, the farm-down will leave Tullow with an 11.76% interest in the upstream and pipeline projects. This is expected to reduce to a 10% interest in the upstream project when the Government of Uganda formally exercises its back-in right. Although it has not yet been determined what interests the Governments of Uganda and Tanzania will take in the pipeline project, Tullow expects its interests in the upstream and pipeline projects to be aligned.

The consideration is split into $200 million in cash, consisting of $100 million payable on completion of the transaction, $50 million payable at FID and $50 million payable at First Oil. The remaining $700 million is in deferred consideration and represents reimbursement in cash of a proportion of Tullow's past exploration and development costs. The deferred consideration is payable to Tullow as the upstream and pipeline projects progress and these payments will be used by Tullow to fund its share of the development costs. Tullow expects the deferred consideration to cover its share of upstream and pipeline development capex to First Oil and beyond. Following meetings in January 2019 between the CEOs of both Tullow and Total and H.E. President Museveni of Uganda, Tullow has agreed the principles for Capital Gains Tax on its $900 million Uganda farm-down to CNOOC and Total. The Government and the JV Partners are now engaged in discussions to finalise an agreement reflecting this tax treatment that will enable completion of the farm-down to take place. Any Capital Gains Tax is expected to be phased and partly linked to project progress. At completion of the farm-down, Tullow anticipates receiving a cash payment of $100 million and a payment of the working capital completion adjustment and deferred consideration for the pre-completion period of $108 million. A further $50 million of cash consideration is due to be received when FID is taken on the development project.

The estimated fair value of the consideration was $829.7 million on recognition. Additions to the value initially recognised related to capitalised interest transferred from intangible exploration and evaluation assets, which were $41.6 million in 2018 (2017: $43.4 million). The present value of the consideration was re-assessed as $840.2 million as at 31 December 2018. The difference to the carrying value of the net assets of the disposal group was transferred back to intangible exploration and evaluation assets before being recognised as an exploration write-off of $74.5 million (refer to note 9).

The major classes of assets comprising the assets classified as held for sale as at 31 December 2018 were as follows:

Uganda	2018 $m	2017 $m
Intangible exploration and evaluation assets	840.2	873.1
Total assets classified as held for sale	840.2	873.1
Net assets of disposal groups	840.2	873.1

13. Trade and other payables

Current liabilities

	2018 $m	2017 $m
Trade payables	97.1	83.3
Other payables	105.1	114.5
Overlifts	16.6	30.4
Accruals	747.8	552.0
VAT and other similar taxes	16.5	17.3
Current portion of finance lease	221.2	228.1
	1,204.3	1,025.6

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 11). The change in trade payables and in other payables predominantly represents timing differences and levels of work activity.

Non-current liabilities

	2018 $m	2017 $m
Other non-current liabilities	91.3	105.1
Non-current portion of finance lease	1,191.0	1,317.5
	1,282.3	1,422.6

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

14. Provisions

	Decommissioning 2018 $m	Other provisions 2018 $m	Total 2018 $m	Decommissioning 2017 $m	Other provisions 2017 $m	Total 2017 $m
At 1 January	897.4	135.0	1,032.4	1,014.4	144.2	1,158.6
New provisions and changes in estimates	(5.8)	155.1	149.3	(33.6)	(9.2)	(42.8)
Disposals	–	–	–	(100.7)	–	(100.7)
Payments	(99.1)	(208.6)	(307.7)	(33.7)	–	(33.7)
Unwinding of discount	14.4	–	14.4	19.7	–	19.7
Currency translation adjustment	(12.9)	–	(12.9)	31.3	–	31.3
At 31 December	794.0	81.5	875.5	897.4	135.0	1,032.4
Current provisions	121.6	76.9	198.5	103.2	127.6	230.8
Non-current provisions	672.4	4.6	677.0	794.2	7.4	801.6

Included within other provisions is provision for onerous service contracts and provision for restructuring costs. Following a trial in the English Commercial Court in May 2018, the court ruled on 3 July that Tullow was not entitled to terminate its West Leo rig contract with Seadrill on 4 December 2016 by invoking the contract's force majeure provisions. Following advice from counsel, Tullow will not be appealing this ruling. Tullow has now paid Seadrill a contractual termination fee, other standby fees that accrued in the 60 days prior to termination of the contract and interest amounting to $248 million in aggregate and a further $11 million of Ghana withholding tax. Although Tullow regards these as joint venture costs, Kosmos disputed separately, through an International Chamber of Commerce arbitration against Tullow, its share of the liability (c. 20%) of any costs related to the use of the West Leo rig beyond 1 October 2016. On 17 July 2018, the arbitration tribunal delivered a final and binding award in favour of Kosmos which determined that Kosmos is not liable for its share of these costs. The arbitration award also provided that Tullow reimburse Kosmos $8.4 million for rig demobilisation costs and certain of its legal costs. In relation to this matter, the Group has recorded an additional pre-tax income statement charge of $161.7 million (2017: credit of $1.0 million).

14. Provisions contd.

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

	Inflation assumption	Discount rate assumption	Cessation of production assumption	2018 $m	2017 $m
Côte d'Ivoire	2%	3%	2026	47.1	49.7
Equatorial Guinea	2%	3%	2028-2029	100.8	133.9
Gabon	2%	3%	2021-2034	50.1	55.8
Ghana	2%	3%	2035-2036	292.1	278.0
Mauritania	n/a	3%	2018	94.8	120.7
UK	n/a	3%	2018	209.1	259.3
				794.0	897.4

15. Dividends

The proposed final dividend for the year, which is subject to approval by shareholders at the Annual General Meeting, and has not been included as a liability in these financial statements is as follows:

	2018 $m
Final dividend proposed in relation to the year	
Ordinary	67.0

Tullow ordinary shareholders with registered addresses in the UK will receive payment of their dividend in pounds sterling. Those with registered addresses in European countries which have adopted the Euro will receive payment of their dividend in Euros. Those holding through the Ghana Stock Exchange will receive payment of their dividend in Ghanaian cedi. The relevant exchange rate to be used to determine the payment of dividends will be the relevant World Market Reuters rate on 12 February 2019.

16. Commercial Reserves and Contingent Resources summary (unaudited) working interest basis

	West Africa		East Africa		New Ventures		TOTAL		
	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Petroleum mmboe
COMMERCIAL RESERVES									
1 January 2018	245.7	268.9	–	–	–	–	245.7	268.9	290.5
Revisions	16.6	8.1	–	–	–	–	16.6	8.1	18.0
Disposals	–	(10.6)	–	–	–	–	–	(10.6)	(1.8)
Transfer from contingent resources	2.5	–	–	–	–	–	2.5	–	2.5
Production	(28.6)	(6.5)	–	–	–	–	(28.6)	(6.5)	(29.7)
31 December 2018	236.3	259.9	–	–	–	–	236.3	259.9	279.6
CONTINGENT RESOURCES									
1 January 2018	121.4	465.1	637.8	42.7	–	4.2	759.1	507.8	844.4
Additions	17.6	80.1	–	–	–	–	17.6	80.1	30.9
Revisions	0.9	16.7	18.9	–	–	–	19.8	16.7	22.6
Disposals and relinquishments	(0.1)	(125.9)	–	–	–	(4.2)	(0.1)	(130.2)	(21.8)
Transfers to commercial reserves	(2.5)	–	–	–	–	–	(2.5)	–	(2.5)
31 December 2018	137.1	436.0	656.7	42.7	–	–	793.8	478.7	873.6
TOTAL									
31 December 2018	373.4	695.9	656.7	42.7	–	–	1,030.1	738.6	1,153.2

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% 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 West Africa revisions to reserves (+18 mmboe) relate mainly to audits of Espoir, Okume, Ezanga and Tchatamaba.
4. The West Africa disposals to gas reserves and resources relates to disposal of the Netherlands assets and cessation production in the UK.
5. The West Africa additions to contingent resources relates to Espoir, Okume, Igongo, Ezanga and Tchatamaba as a result of the recognition of potential from additional evaluations.
6. The East Africa addition to oil contingent resources relates mainly to the audit of Etom discovery in Kenya.

The Group provides for depletion and amortisation of tangible fixed assets on a net entitlements basis, which reflects the terms of the Production Sharing Contracts related to each field. Total net entitlement reserves were 264.9 mmboe at 31 December 2018 (31 December 2017: 284.1 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.

About Tullow Oil plc

Tullow is a leading independent oil & gas, exploration and production group, quoted on the London, Irish and Ghanaian stock exchanges (symbol: TLW). The Group has interests in 85 exploration and production licences across 17 countries which are managed as three business delivery teams: West Africa, East Africa and New Ventures.

EVENTS ON THE DAY

In conjunction with these results, Tullow is conducting a Presentation in London 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:

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