TULLOW OIL PLC

2015
FULL YEAR RESULTS

10 February 2016

Tullow Oil plc – 2015 Full Year Results

2015 revenue of $1.6 billion and pre-tax operating cash flow of $1.0 billion
TEN Project over 85% complete and on track for first oil between July and August 2016
Action being taken to reduce $1.1 billion 2016 capex; Ability to reduce to $0.3 billion from 2017

10 February 2016 – Tullow Oil plc (Tullow), the independent oil and gas exploration and production group, announces its full year results for the year ended 31 December 2015. Details of a presentation in London, webcast and conference calls are available on page 26 of this report or visit the Group's website www.tullowoil.com.

COMMENTING TODAY, AIDAN HEAVEY, CHIEF EXECUTIVE, SAID:

"Today's results demonstrate that Tullow adjusted well to low oil prices in 2015. We secured current and future cash flow through good operational delivery in West Africa, continued to build our resource base in East Africa, significantly cut costs across the Group and benefitted from our strong hedging position. Our challenge in 2016 is to be equally robust in responding to the uncertainties that remain in the sector. In the year ahead, we have three key priorities: ensuring continued low cost production from West Africa - including the start-up of production from TEN between July and August 2016; driving further reductions in operating costs and capital expenditure; and focusing on deleveraging the balance sheet through free cash flow generation and strategic portfolio management. As we look ahead, we have a portfolio of world class, low cost oil assets which will produce around 100,000 bopd in 2017 and a major position in one of the world's newest, low cost, oil provinces in East Africa, both enabling us to create substantial value."

2015 FULL YEAR RESULTS SUMMARY

- Revenues down 27% on previous year; write-offs and impairment charges also impacted by the oil price decline, resulting in a loss after tax of $1.0 billion. Strong operating cash flow generation of $1.0 billion from stable production.
- Year-end 2015 net debt of $4.0 billion with significant facility headroom and free cash of $1.9 billion. RBL and RCF capacity increased by $450 million in March 2015; banking discussions with regard to March 2016 re-determination have begun.
- Mark-to-market value of oil hedges at 31 January 2016 of $668 million with 52% of 2016 entitlement oil production hedged at average floor price of around $75/bbl on a pre-tax basis (64% hedged on a post-tax basis); material 2017 hedging in place.
- Major Simplification Project completed resulting in improved organisational structure, efficient processes and reduced headcount of 37%; on track to deliver cash savings of around $500 million over three year period.
- Low cost per barrel oil production at Jubilee and the West Africa non-operated portfolio with 2015 opex at $10.0/bbl and $15.0/bbl respectively; cost savings and synergies from Jubilee and TEN in Ghana to achieve around $8/bbl opex in 2018.
- 2015 capex of $1.7 billion; $1.1 billion forecast for 2016 with work ongoing to potentially reduce to $0.9 billion; ability to reduce Group annual capex to c.$0.3 billion from 2017 onwards if the low oil price persists.
- West Africa working interest oil production averaged 66,600 bopd in 2015; production guidance in 2016 for the region is 73-80,000 bopd. TEN Project over 85% complete and on track and on budget for first oil between July and August 2016.
- Successful Kenya appraisal programme underpins estimated gross recoverable resource guidance of 600mmbo.

FINANCIAL OVERVIEW	FY 2015	FY 2014	Change
Sales revenue ($m)	1,607	2,213	-27%
Gross profit ($m)	591	1,096	-46%
Administrative expenses ($m)	(194)	(192)	-1%
Restructuring costs ($m)	(41)	-	-
Loss on disposal ($m)	(57)	(482)	88%
Goodwill impairment ($m)	(54)	(133)	60%
Exploration costs written off ($m)	(749)	(1,657)	55%
Impairment of property, plant and equipment ($m)	(406)	(596)	32%
Provision for onerous service contracts ($m)	(186)	–	–
Operating loss ($m)	(1,094)	(1,965)	44%
Loss after tax ($m)	(1,037)	(1,640)	37%
Operating cash flow before working capital ($m)	967	1,545	-38%

2015 Full Year Results overview

Group performance

Tullow's 2015 financial results delivered solid revenue and pre-tax operating cash flow of $1.6 billion and $1.0 billion respectively, down on 2014, reflecting the significant fall in commodity prices over the year. Revenues and cash flow were supported by our significant hedging programme. The Group reported a loss after tax of $1.0 billion following write-downs exacerbated by lower oil prices. These included an exploration pre-tax write-off totalling $749 million, a pre-tax impairment charge of $406 million and an onerous service contract charge of $186 million as a result of much lower levels of exploration and appraisal drilling activity planned for the first half of 2016. Further details are provided in the Finance Review.

Responding to the lower oil price

A focus on lower capex, cost savings and improved efficiency has positively benefited the cash flows of the business. The Major Simplification Project commenced at the end of 2014, was completed in 2015, and is on track to deliver cash capex, opex and corporate cost savings of $0.5 billion over three years. In 2015, gross G&A was $164 million lower than the previous year. Capex reduced from $2.2 billion in 2014 to $1.7 billion in 2015 and is forecast at $1.1 billion for 2016 with work ongoing to potentially reduce this to around $0.9 billion. The 2016 capex programme comprises $0.6 billion for the TEN project, c.75% of which is to be invested in the first half of 2016 and $0.4 billion for other production and development activities. Exploration will continue to be a key part of Tullow's long-term growth strategy, however, given sustained low oil prices, capex will be around $0.1 billion in 2016. It will focus on seismic surveying, processing and interpretation, high-grading and progressing leads to drill worthy prospects and seeking low cost and highly prospective acreage in core areas to ensure that the business maintains its industry-leading exploration portfolio. As we look forward, with the capital intensive period of the TEN project behind us, the Group could, if market conditions do not improve, reduce capex to around $0.3 billion for 2017 onwards due to considerable flexibility around the timing of incremental investments.

Balance sheet and funding strategy

Tullow benefits from a diversified debt capital structure and during 2015, Tullow increased the capacity of its RBL and Corporate Facilities by $450 million. As of 31 December 2015, the Group had net debt of $4.0 billion, with facility headroom and free cash of $1.9 billion. The Group has benefited significantly from its hedging programme which contributed some $365 million, net of premiums, to the revenue of the business in 2015. The hedging programme will continue to provide future cash flow benefits and the mark-to-market value of the hedges at the end of January 2016 was $668 million. Dialogue with Tullow's syndicate of lending banks has commenced as we prepare for the redetermination of the Group's RBL in March. In October 2016, the RBL will begin to amortise and the Group expects to refinance the facility ahead of further scheduled amortisations in 2017. In addition, the Group will negotiate to extend the three year Revolving Corporate Facility ahead of April 2017. Delivery of these actions, along with reduced committed capital expenditure, further cost savings, cash flow generation and strategic portfolio management will strengthen and de-lever the balance sheet.

Strong West Africa production performance

In 2015, production across the Group was in line with expectations. West Africa working interest oil production averaged 66,600 bopd. In Europe, gas production averaged 6,800 boepd. Average working interest production guidance for 2016 from West Africa and Europe is 73,000-80,000 bopd and 5,000-7,000 boepd respectively. This includes production in the second half of 2016 from the TEN development as it gradually ramps up following first oil. In 2015, Tullow's operating costs per barrel in West Africa remained low averaging $10.0/bbl for Jubilee and $15.0 bbl across the West Africa non-operated portfolio. Tullow continues to focus on improving efficiencies and operating costs across its West Africa asset base and is working to maximise Jubilee and TEN operational synergies in Ghana where combined operating costs are expected to reduce to c.$8/bbl in 2018.

Major development projects

The TEN project in Ghana remains on track for first oil between July and August 2016. The project is over 85% complete, with many major milestones achieved including the sailaway of the FPSO from Singapore on 23 January 2016. The Greater Jubilee Full Field Development (GJFFD) Plan was submitted to the Government of Ghana in December. The plan, which intends to extend production and increase commercial reserves, has been redesigned given the current environment to reduce the overall capital requirement and allow flexibility in the timing of the investment. In East Africa, a draft Field Development Plan was submitted to the Government of Kenya in December 2015 and this will inform discussions as Tullow and its Partners progress towards potential FID of both the Kenya and Uganda upstream development projects.

Board changes, AGM and dividend

At the end of 2015, Graham Martin retired as Company Secretary and will step down as Executive Director at the AGM. Tullow's AGM will take place on 28 April 2016 at 12pm at Tullow Oil plc, Building 9, Chiswick Park, 566 Chiswick High Road, London, W4 5XT. In view of current capital allocation priorities, the Board is again recommending that no dividend is paid. At a time when Tullow is focusing on financial flexibility and cost reductions, the Board believes that Tullow and its shareholders are better served by retaining these funds in the business.

Operations review

WEST AFRICA*

2015 net production	Total net reserves and resources	2015 net sales revenue	2015 net investment
73,400 bopd	559 mmboe	$1,607 million	$1,286 million

*Tullow's West Africa Business Delivery Team also manages the Group's European production and development operations which are reflected in the above table

Ghana

Jubilee

The Jubilee field exceeded its gross production target during 2015 averaging 102,600 bopd (net: 36,400 bopd). A stable rate of gas offtake has been achieved following final commissioning of the onshore gas processing plant in March 2015, averaging around 90 mmscfd in the fourth quarter of the year. This strong gas export performance significantly reduced the requirement for gas reinjection at the field. Tullow is forecasting Jubilee 2016 average production to be around 101,000 bopd gross (net: 36,000 bopd). This reflects the impact of a planned two week FPSO maintenance shutdown scheduled for March 2016 and a period of reduced water injection capacity during the first half of the year which is currently being addressed.

During the year, Jubilee Phase 1A drilling and completions continued with two oil producers coming on stream in September and December and a water injector which has yet to be completed. With the Phase 1A investment programme nearing completion, Tullow and partners submitted the Greater Jubilee Full Field Development (GJFFD) Plan in December 2015 and discussions are ongoing with the Government regarding its progress. This project, to extend field production and increase commercial reserves, has been redesigned given the current environment to reduce the overall capital requirement and allow flexibility in the timing of the capital investment. During 2016 and beyond, a continued focus on cost reduction opportunities and the careful balancing of future capital investment initiatives, including infill drilling as part of the GJFFD, will be key as Tullow seeks to ensure maximum return on investment from this world-class oil field.

TEN

The TEN project continues to make excellent progress, is over 85% complete, and remains within budget and on schedule for first oil between July and August 2016. To date, all the key milestones of the project have been met, including the sailaway of the TEN FPSO from Singapore to Ghana on 23 January 2016. The vessel sailed with almost zero "carry over", which means that only 2,000 man hours out of a total 17 million man hours of work remain to be completed during the vessel's journey to Ghana, a very significant industry achievement. Arrival in Ghana is expected to be in early March and the vessel will move directly to the installation phase where it will be fixed to the seabed using pre-installed anchor chains and piles. This is followed by the hook-up of subsea facilities to the FPSO via flowline risers and control umbilicals, much of which has also been pre-installed. The eleven pre-drilled wells are now being completed with the sixth completion under way. The integrated facilities will undergo final commissioning and testing during the second quarter and following start-up, a gradual ramp up in production towards plateau is anticipated during the second half of 2016. Tullow estimates that TEN average production in 2016 will be around 23,000 bopd gross (net: 11,000 bopd).

The overall gross capex cost of the development remains at around $5 billion, without FPSO lease costs. Total gross capex to first oil is expected to be around $4 billion after which the remaining capex is largely associated with the drilling and completion of an additional 13 wells. The export of associated gas from the TEN field is scheduled to start up one year after first oil. Tullow is guiding 2016 net capex for the development to be around $600 million with approximately 75% being spent in the first half of the year in preparation for first oil.

In April 2015, the Special Chamber of the International Tribunal of the Law of the Sea (ITLOS) in Hamburg rejected Côte d'Ivoire's request that Ghana be ordered to suspend all oil exploration and exploitation in the disputed zone including the TEN Project. ITLOS ordered a number of provisional measures which both Ghana and Côte d'Ivoire are required to comply with; including continued cooperation and 'no new drilling' until ITLOS gives its decision on the maritime boundary dispute which is expected in late 2017. It is therefore assumed that development drilling will not recommence until the ITLOS proceedings have completed.

West Africa non-operated portfolio

Working interest oil production from Tullow's non-operated West African portfolio was in line with guidance in 2015, averaging 30,200 bopd net. The region still generates important operating cash flow for the Group with a low average operating cost of $15.0/bbl. Production from the region is expected to be around 29,500 bopd net in 2016. Capital investment on development activities in 2016 will be reduced to around $100 million net to Tullow versus spend in 2015 of around $200 million. The strategy across the portfolio is to target investment decisions on activities that limit the decline rates of these mature fields.

In Côte d'Ivoire, the first five wells of the Espoir Phase 3 infill campaign have successfully been completed. Around 14,000 bopd gross have been added to the Espoir field's production since the start of the drilling programme. Up to a further six wells are due to be drilled in 2016 which will continue to support strong production from the field.

In Congo (Brazzaville), additional infill wells were drilled across the M'Boundi field during 2015. The rig was released in July and the partners are reviewing field performance before a rig returns to drill a further three wells in the second half of 2016.

In Equatorial Guinea, activity during 2015 was focused on improving operating efficiencies and asset integrity at the Hess operated Ceiba and Okume fields. A subsea workover on an existing Ceiba well will be completed in the second quarter 2016. The Joint Venture is currently reviewing the new 4D seismic shot over the Okume Complex to prepare an infill inventory to restart drilling on Elon and Oveng in 2017.

In Gabon, the drilling programs on the Perenco operated fields finished in late 2015. Field performance reviews are taking place with the hopes of restarting drilling late 2016. The Etame infill drilling program yielded good results at the new Etame and SEENT wellhead platforms. Focusing on driving down operating costs remains a key objective ahead of a potential resumption in drilling operations in late 2016 or early 2017. During the year, Tullow regained its 7.5% stake in the Onal Complex producing fields and the Ezanga block (formerly the Omoueyi exploration block). In addition, Tullow has been granted licence extensions in the Onal Complex fields until 2034 and has gained access to two small oil discoveries made within the Ezanga block in 2014. In return for access to these discoveries, it was agreed that the effective date of the new licence would be 1 August 2015.

EAST AFRICA

2015 net production nil bopd	Total net reserves & resources 636 mmboe	2015 net sales revenue $nil million	2015 net investment $305 million

Kenya

In 2015, Tullow's activities in Kenya largely focused on completing the appraisal of the South Lokichar Basin discoveries, gaining important reservoir data for the field development plans. Nine appraisal wells were drilled and five Extended Well Tests (EWTs) were successfully completed at the Ngamia and Amosing fields.

Successful appraisal wells drilled included Ngamia-7, 8 and 9, Amosing-3, 4 and 5, Twiga-3, Ekales-2 and Etom-2. In December, Etom-2, the most recent well drilled in the South Lokichar Basin, discovered 102 metres of net oil pay in high quality reservoir sands in an untested fault block identified on new 3D seismic. The results of these appraisal wells have significantly advanced the subsurface definition of the main South Lokichar discoveries.

The EWTs conducted at the Amosing and Ngamia fields have demonstrated production rates and reservoir continuity over distances suitable for field development. In the Amosing EWT, five separate zones were completed in the Amosing-1 and 2 wells. The five zones produced at a cumulative average constrained rate of 4,300 bopd oil under natural flow conditions and good pressure communication was observed between the wells. For the Ngamia EWTs, five separate zones were completed in the Ngamia-3, 6 and 8 wells. The five zones produced at a cumulative average constrained rate of 2,400 bopd and all except the lowest zone produced under natural flow conditions. During the EWTs, approximately 68,000 barrels of oil were produced into storage.

Completion of the appraisal drilling and testing campaign in the South Lokichar Basin underpins an estimated gross contingent recoverable resource base of 600 mmbo. The new 3D seismic, which was used to locate the Etom-2 well which encountered the best oil reservoir quality to date, indicates significant remaining exploration prospectivity in the greater Etom area. This supports an upside potential of 1 billion barrels of oil in the South Lokichar Basin. Plans for further exploration drilling to test this upside will be evaluated during the first half of 2016.

Outside of the South Lokichar Basin frontier exploration activity continued in 2015. Three potential basin opening exploration wells were drilled across Tullow's extensive Kenyan acreage in the North Kerio (Epir-1), North Turkana (Engomo-1) and North Lokichar (Emesek-1) Basins. While none of the wells were discoveries, they have provided valuable data to assess the wider prospectivity of the basins. There is significant remaining exploration potential in the basins outside of South Lokichar and future basin opening exploration drilling plans are currently being evaluated.

The Cheptuket-1 exploration well in Block 12A spudded on 28 December. The well will test a basin bounding structural closure in the undrilled Kerio Valley Basin, in a similar structural setting to the successful Ngamia and Amosing discoveries in the South Lokichar Basin. Cheptuket-1 will likely complete drilling in late February after which the PR Marriott Rig-46 will demobilise, marking the end of the current drilling campaign.

In November, Tullow agreed to farm down 25% of its 65% operated working interest in Block 12A to Delonex for a carry. This farm-down was completed on 28 January 2016.

Uganda

In Uganda, all appraisal activities and pre-FEED studies have been completed. Significant progress has been made on several fiscal matters and in June 2015, the Government of Uganda announced that it had amended the VAT Act to exempt oil exploration and development from VAT. Later in June, Tullow announced that it had agreed to pay the Uganda Revenue Authority $250 million in full and final settlement of its CGT liability for the farm-downs to Total and CNOOC completed in 2012. This sum comprises $142 million that Tullow paid in 2012 and $108 million to be paid in three equal instalments. The first of these was paid upon settlement and the remainder will be paid in 2016 and 2017. These decisions are important steps towards the sanction of the Lake Albert development. In July 2015, Tullow prequalified for the upcoming Uganda exploration bid round and evaluation is currently underway ahead of the 26 February bid deadline.

East Africa Development

Good progress continues to be made on development planning in Kenya. A draft Field Development Plan was submitted to the Government of Kenya in December and will inform discussions as we progress towards potential FID of both the Kenya and Uganda upstream development projects and preparation for FEED is under way in both countries. Scoping studies and terms of reference for the detailed upstream environmental and social impact assessments were submitted to the regulatory authorities in both countries.

In August 2015, a bilateral agreement was reached between the Presidents of Uganda and Kenya adopting the Northern Kenya route for the regional crude oil pipeline, subject to certain conditions. These conditions, which include ensuring that this is the lowest cost route, are being worked on by both Governments in conjunction with the Kenyan and Ugandan upstream parties.

NEW VENTURES

2015 net production nil bopd	Total net reserves & resources 102 mmboe	2015 net sales revenue $nil million	2015 net investment $129 million

Over 2015, Tullow has undertaken a strategic review of its New Ventures portfolio to determine how it can best use this period of reduced industry exploration activity to prepare for future growth. The focus has been on enhancing Tullow's licence and prospect inventory in preparation for increasing drilling activity in future years. The Group has also been actively managing its current equity positions and exposure to drilling costs across the portfolio through various transactions for carried interests. A number of farmdowns are under way across the portfolio and this work will continue in the coming year. In 2016, our main focus will be to continue to selectively replenish and high grade the exploration portfolio for future growth.

Africa

In Mauritania, 2D seismic was acquired in the Block C-3 licence during the first quarter of 2015 and Tullow is hopeful of acquiring a new 3D survey across the shelf prospectivity in Blocks C-3 and C-10 during the next 12 to 24 months to determine the exploration potential of both licences and areas for future exploration activity. In June 2015, the Group agreed to farm down a 13.5% interest in Block C-10 to Sterling Energy.

In Guinea, discussions have been ongoing with the Government and our Partners regarding the resumption of petroleum operations. SCS Corporation, a subsidiary of Hyperdynamics Corporation, has unilaterally declared these discussions to be at an impasse and has commenced legal action against the other members of the joint venture.

In Gabon, further 3D seismic data was acquired during Q1 2015 in the Arouwe block in Gabon, the results of which are currently under review.

In Namibia, interpretation of the 3D survey across the PEL30 and PEL37 licences has yielded significant prospectivity in shallow water in close proximity to the Wingat well in the adjacent licence which encountered oil in the Cretaceous.

South America & Caribbean

Tullow has been active in the South America and Caribbean region in 2015, an area the Group considers to have great potential. In Suriname, a 4,000 sq km 3D seismic programme of the Tullow-operated offshore Block 54 was completed in September 2015. This was followed by a 20% farm out of Block 54 in October 2015 to Noble for a carry, leaving Tullow with a 30% interest and retained operatorship. Tullow and its partners are reviewing the very encouraging results of the seismic programme ahead of selecting future drilling prospects. In the neighbouring Block 47, a two year licence extension has been granted and a drop core survey is planned to be completed in 2016. The Spari-1 well in offshore Block 31 was completed in August 2015 and was subsequently plugged and abandoned. Despite the presence of targeted Campanian turbidite sands in the well, no significant hydrocarbon shows were encountered.

In Guyana, Tullow and its Partners continue to evaluate and map prospectivity in the offshore Kanuku licence and an 18 month extension has been requested to allow a new 3D survey to be acquired. In early 2016, Tullow was awarded a 60% operated interest in the Orinduik licence, a 1,801 square kilometre block offshore Guyana. Both of Tullow's Guyana licences sit close to Exxon Mobil's 'Liza' oil discovery which was announced in 2015.

In Jamaica, a 2D seismic survey is underway over the 32,056 sq km Walton Morant licence and will be completed in the first quarter of 2016 to delineate potential plays in shallow water. In Uruguay, good progress has been made in mapping the large 3D dataset and a number of prospects have been identified.

Europe

Exploration activity continued offshore Norway in 2015 with the non-operated Bjaaland, Zumba and Salander wells. All three wells were unsuccessful and were plugged and abandoned. Tullow actively managed its equity position and exposure to drilling costs in Norway and the Group reduced its equity in the Zumba well from 60% to 40% (paying 32.5%) and farmed out its remaining 20% interest in the unsuccessful Hagar well in PL650, ahead of drilling for a cash payment.

In Norway, the Group made applications in the 23rd licensing round and was recently awarded 8 licences in the 2015 APA licence round. In 2016, four wells are planned to be drilled to test the Cara prospect adjacent to the Gjoa field, the Rovarkula prospect adjacent to the Ivar Hansen field, the Rome well adjacent to Johan Sverdrup field and a recently spudded horizontal well in the Wisting Discovery.

Asia

The Kup-1 well in the Kalchas block in Pakistan, in which Tullow has a 30% non-operated stake, reached total depth in December 2015. Over 400 metres of weak gas shows were encountered in fractured sandstone reservoirs and a drill stem test programme has commenced to establish hydrocarbon presence and productivity. In January 2016, Tullow agreed to sell a 20% interest in the Bannu West licence in Pakistan to Mari Petroleum. The deal is subject to Government approval.

Finance Review

Financial results summary	2015	2014	Change
Working interest production volume (boepd)	73,400	75,200	-2%
Sales volume (boepd)	67,600	67,400	0%
Realised oil price ($/bbl)	67.0	97.5	-31%
Realised gas price (p/therm)	41.8	51.7	-19%
Sales revenue ($m)	1,607	2,213	-27%
Cash operating costs ($per boe)	15.1	18.6	-19%
Exploration write-off ($m)	749	1,657	-55%
Impairment of property, plant and equipment ($m)	406	596	-32%
Operating loss ($m)	(1,094)	(1,965)	44%
Loss before tax ($m)	(1,297)	(2,047)	37%
Loss after tax ($m)	(1,037)	(1,640)	37%
Basic earnings per share (cents)	(113.6)	(170.9)	34%
Cash generated from operations (before working capital) ($m)	967	1,545	-37%
Operating cash flow (before working capital) per boe ($/bbl)	35.9	56.1	-36%
Dividend per share (pence)	–	4.0	–
Capital investment ($m)	1,720	2,020	-15%
Net debt ($m)	4,019	3,103	30%
Gearing (net debt/net assets plus net debt) (%)	56	44	12

Production and commodity prices

Working interest production averaged 73,400 boepd, a decrease of 2% for the year (2014: 75,200 boepd). Growth in low cost West Africa oil production was offset by the end of field life declines in UK gas production, the partial farm-down of the Schooner and Ketch gas fields in October 2014 and the disposal of the Netherlands Q&L blocks in April 2015. Sales volumes for West Africa oil and European gas averaged 60,000 bopd and 7,600 boepd respectively.

On average, oil prices in 2015 were lower than in 2014 due to the oil price falling significantly since the third quarter 2014. Realised oil price after hedging for 2015 was US$67.0/ bbl (2014: US$97.5/bbl), a decrease of 31% versus a 47% decrease in Brent oil prices over the period. European gas prices in 2015 were lower than 2014. The realised European gas price after hedging for 2015 was 41.8 pence/therm (2014: 51.7 pence/therm), a decrease of 19%.

Operating costs, depreciation, impairments and expenses

Underlying cash operating costs, which exclude depletion and amortisation and movements in underlift / overlift, amounted to $406 million; $15.1/boe (2014: $512 million; $18.6/boe). The decrease of 19% in underlying cash operating costs per barrel is principally due to increased West African production combined with on-going cost savings and the impact of the farm-down and disposal in the UK and Netherlands which have higher than average cash operating costs per barrel.

DD&A charges before impairment on production and development assets amounted to $551 million; $20.5/boe (2014: $572 million; $20.8/boe). The Group recognised an impairment charge of $406 million (2014: $596 million) in respect of lower forecast oil and gas prices and an increase in anticipated future decommissioning costs offset both by impairment write backs in Gabon due to increased reserves and by lower forecast decommissioning costs in the UK. The impairment charge net of tax amounted to $357 million. The Group recognised an impairment in relation to goodwill of $54 million (2014: $133 million).

Administrative expenses of $194 million (2014: $192 million) include an amount of $48 million (2014: $38 million) associated with IFRS 2 – Share-based Payment accruals. The MSP was undertaken during 2015, is on track to deliver cash savings of around $500 million over a three-year period and has resulted in a workforce reduction of 37% to date.

During 2015, the Group recognised a provision for restructuring costs of $45 million. After recharges to JV partners the net restructuring costs included in the income statement is $41 million. This has been presented separately from administrative expenses in the income statement.

Exploration costs written off	2015 $m	2014 $m
Exploration costs written-off	(749)	(1,657)
Associated deferred tax credit	277	398
Net exploration costs written-off	(472)	(1,259)

During 2015, the Group spent $256 million, including Norway exploration costs on a post-tax basis, on exploration and appraisal activities and has written off $130 million in relation to this expenditure. This included write-offs in Suriname ($28 million), Norway ($11 million), Kenya ($28 million) and new venture costs ($19 million). In addition, the Group has written-off $343 million in relation to prior years' expenditure as a result of a review of future work programmes based on capital relocation to focus on the Group's key development projects and the impact of the current low oil price environment. This included write-offs in the Netherlands ($186 million), Guinea ($54 million), Greenland ($39 million), Ethiopia ($35 million), Gabon ($9 million) and Madagascar ($11 million).

Provision for onerous service contracts

At the end of 2015, Tullow has provided $186 million for onerous service contracts due to the reduction in planned future activity.

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 reinvestment in capital programmes that are driving business growth.

At 31 December 2015, the Group's derivative instruments had a net positive fair value of $623 million (2014: positive $471 million), net of deferred premium ($101 million). While all of the Group's commodity derivative instruments currently qualify for hedge accounting, a pre-tax charge of $59 million (2014: credit of $51 million) in relation to the change in time value of the Group's commodity derivative instruments has been recognised in the income statement for 2015.

Hedge position at 31 January 2016	2016	2017	2018
Oil hedges			
Volume – bopd	36,511	23,000	9,500
Average floor price protected ($/bbl)	75.14	72.94	62.09

Net financing costs

The net interest charge for the year was $145 million (2014: $134 million). The increase in finance costs is associated with an increase in net debt but partially offset by an increase in capitalised interest on the TEN development. The 2015 net interest charge includes interest incurred on the Group's debt facilities and the decommissioning finance charge offset by interest earned on cash deposits and borrowing costs capitalised principally against the Ugandan assets and the TEN development.

Taxation

The net tax credit of $260 million (2013: $408 million, credit) relates to a tax charge in respect of the Group's North Sea, Gabon, Equatorial Guinea and Ghanaian production activities offset by the tax credits arising from Norwegian exploration and deferred tax credits associated with exploration write-offs and impairments. After adjusting for disposals, restructuring costs, exploration write-offs and impairments, the related deferred tax benefit in relation to the exploration write-offs and impairments and profits/losses on disposal, the Group's underlying effective tax rate was 29% (2014: 24%). The increase in underlying effective tax rate is primarily a result of lower PSC income and the tax credit recognised on the derivative financial instruments in 2014.

Loss after tax from continuing activities and loss earnings per share

The loss from continuing activities for the year amounted to $1,037 million (2014: $1,640 million loss). Basic loss per share was 113.6 cents (2014: 170.9 cents loss).

Dividend per share

In view of the fall in the oil price, the Board has suspended the dividend in early 2015. At a time when Tullow is focusing on capital allocation, financial flexibility and cost reductions, the Board believes that Tullow and its shareholders are better served by investing these funds into the business.

Operating cash flow

Operating cash flow before working capital movements decreased by 37% to $1.0 billion (2014: $1.5 billion) as a result of reduced sales volumes and lower realised commodity prices partially offset by lower cash operating costs. In 2015, this cash flow together with increased debt facilities helped fund the Group's $1.7 billion of capital expenditure in exploration and development activities and $232 million servicing the Group's debt facilities.

Reconciliation of net debt	$m
Year-end 2014 net debt	**(3,103)**
Revenue	1,607
Operating costs	(406)
Operating expenses	(234)
Cash flow from operations	**967**
Movement in working capital	349
Tax paid	35
Capital expenditure	(2,112)
Disposals	56
Other investing activities	4
Financing activities	(232)
Foreign exchange gain on cash and debt	17
Year-end 2015 net debt	**(4,019)**

Capital expenditure

2015 capital expenditure amounted to $1.7 billion (2014: $2.0 billion) (net of Norwegian tax) with $1.5 billion invested in development activities and $0.2 billion in exploration and appraisal activities. More than 80% of the total was invested in Kenya, Ghana and Uganda and over 90%, more than $1.6 billion, was invested in Africa. Based on current estimates and work programmes, 2016 capital expenditure is currently forecast to be up to $1.1 billion (net of Norwegian tax), with $100 million allocated to exploration and appraisal activities and work ongoing to potentially reduce 2016 capital expenditure to around $0.9 billion.

Portfolio management

On 30 April 2015, Tullow completed the sale of its operated and non-operated interests in the L12/15 area and Blocks Q4 and Q5 in the Netherlands to AU Energy. The consideration was €64 million producing a profit after tax of $7.4 million and a loss before tax of $46.3 million. On 5 June 2015, Tullow completed the farm-down to GDF Suez E&P Nederland of 30% interests in, and the operatorship of, Exploration Licences E10, E11 (including Tullow's Vincent discovery), E14, E15c and E18b.

Balance sheet

In the first half of 2015, Tullow increased its commitments under the Revolving Corporate Facility from $0.75 billion to $1.0 billion and commitments under the Reserve Based Lending Facility increased from $3.5 billion to $3.7 billion. Furthermore, amendments to the financial covenants on the Reserve Based Lending Facility and Revolving Corporate Facility were agreed to address the risk of any potential covenant breach during a period of oil price volatility and investment in production and development assets in West Africa. At 31 December 2015, Tullow had net debt of $4.0 billion (2014: $3.1 billion). Unutilised debt capacity and free cash at 31 December 2015 amounted to approximately $1.9 billion. Total net assets at 30 December 2015 amounted to $3.2 billion (2014: $4.0 billion) with the decrease in total net assets principally due to the loss during 2015 from continuing activities.

Liquidity risk management and going concern

The Group closely monitors and manages its liquidity risk. Cash forecasts are regularly produced and sensitivities run for different scenarios including, but not limited to, changes in commodity prices, different production rates from the Group's producing assets and delays to development projects. In addition to the Group's operating cash flows, portfolio management opportunities are reviewed to potentially enhance the financial capability and flexibility of the Group. In the currently low commodity price environment, the Group has taken appropriate action to reduce its cost base and had $1.9 billion of debt liquidity headroom and free cash at the end of 2015. The Group's forecast, taking into account the risks described above, 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 2015 Annual Report and Accounts.

Notwithstanding our forecasts of liquidity headroom throughout the 12 month period, there remains a risk, given the volatility of the oil price environment and its impact on operating cash flows and facility availability, that the Group's liquidity position may deteriorate and/or the Group may become technically non-compliant with one of its financial covenants at the end of 2016.

To mitigate this risk, we will continue to maintain our long-term banking relations and will monitor our cash flow projections and, if necessary, take mitigating actions well in advance to maintain our liquidity and compliance with covenants. Actions available to the Group include further rationalisation of our cost base, cuts to discretionary capital expenditure, portfolio management and other funding options.

Based on this analysis, the directors have adopted the going concern basis of accounting in preparing the annual financial statements.

2016 principal financial risks and uncertainties

The principal financial risks to performance identified for 2016 are:

- Oil price and overall market volatility
- Operational performance and project delivery
- Maintaining capital and operating cost discipline
- Execution of financial strategy to maintain appropriate liquidity

Events since year-end

In January 2016 Tullow completed the farm-down of 25% of its interest in block 12A to Delonex and Tullow also agreed to sell a 20% interest in the Bannu West licence in Pakistan to Mari Gas. Tullow was awarded a 60% operated interest in the Orinduik licence in January 2016, a 1,801 square kilometre block offshore Guyana. On 23 January 2016, the TEN FPSO set sail from Singapore to Ghana with arrival expected in early March 2016.

Subsequent to the balance sheet date there has been a deterioration in the spot price of Brent crude. Sensitivity analysis on the impact of a reduction in Brent crude prices on the carrying value of PP&E is provided in note 10.

Condensed consolidated income statement

Year ended 31 December 2015

	Notes	2015 $m	2014 $m
Continuing activities			
Sales revenue		1,606.6	2,212.9
Cost of sales	7	(1,015.3)	(1,116.7)
Gross profit		591.3	1,096.2
Administrative expenses	7	(193.6)	(192.4)
Restructuring costs	7	(40.8)	–
Loss on disposal		(56.5)	(482.4)
Goodwill impairment		(53.7)	(132.8)
Exploration costs written off	9	(748.9)	(1,657.3)
Impairment of property, plant and equipment, net	10	(406.0)	(595.9)
Provision for onerous service contracts		(185.5)	–
Operating loss		(1,093.7)	(1,964.6)
(Loss)/gain on hedging instruments		(58.8)	50.8
Finance revenue		4.2	9.6
Finance costs		(149.0)	(143.2)
Loss from continuing activities before tax		(1,297.3)	(2,047.4)
Income tax credit	8	260.4	407.5
Loss for the year from continuing activities		(1,036.9)	(1,639.9)
Attributable to:			
Owners of the Company		(1,034.8)	(1,555.7)
Non-controlling interest		(2.1)	(84.2)
		(1,036.9)	(1,639.9)
Loss per ordinary share from continuing activities		¢	¢
Basic	2	(113.6)	(170.9)
Diluted	2	(113.6)	(170.9)

Condensed consolidated statement of comprehensive income and expense

Year ended 31 December 2015

	2015 $m	2014 $m
Loss for the year	(1,036.9)	(1,639.9)
Items that may be reclassified to the income statement in subsequent periods		
Cash flow hedges		
Gains arising in the year	513.0	485.7
Reclassification adjustments for items included in (loss)/profit on realisation	(302.4)	4.6
Exchange differences on translation of foreign operations	(43.6)	(50.6)
Other comprehensive income	167.0	439.7
Tax relating to components of other comprehensive income	(42.3)	(91.0)
Net other comprehensive income for the year	124.7	348.7
Total comprehensive expense for the year	(912.2)	(1,291.2)
Attributable to:		
Owners of the Company	(910.1)	(1,207.0)
Non-controlling interest	(2.1)	(84.2)
	(912.2)	(1,291.2)

Condensed consolidated balance sheet

As at 31 December 2015

	Notes	2015 $m	2014 $m
ASSETS			
Non-current assets			
Goodwill		164.0	217.7
Intangible exploration and evaluation assets	9	3,400.0	3,660.8
Property, plant and equipment	10	5,204.4	4,887.0
Investments		1.0	1.0
Other non-current assets	11	223.4	119.7
Derivative financial instruments		218.7	193.9
Deferred tax assets		295.3	255.0
		9,506.8	9,335.1
Current assets			
Inventories		107.2	139.5
Trade receivables		80.8	87.8
Other current assets	11	763.2	902.3
Current tax assets		127.6	221.6
Derivative financial instruments		406.5	280.8
Cash and cash equivalents		355.7	319.0
Assets classified as held for sale		–	135.6
		1,841.0	2,086.6
Total assets		11,347.8	11,421.7
LIABILITIES			
Current liabilities			
Trade and other payables	12	(1,110.6)	(1,074.9)
Provisions	13	(187.0)	–
Borrowings		(73.8)	(131.5)
Current tax liabilities		(208.3)	(115.9)
Derivative financial instruments		(2.1)	(3.3)
Liabilities directly associated with assets classified as held for sale		–	(13.6)
		(1,581.8)	(1,339.2)
Non-current liabilities			
Trade and other payables	12	(99.3)	(85.1)
Borrowings		(4,262.4)	(3,209.1)
Provisions	13	(1,065.1)	(1,260.4)
Deferred tax liabilities		(1,164.5)	(1,507.6)
		(6,591.3)	(6,062.2)
Total liabilities		(8,173.1)	(7,401.4)
Net assets		3,174.7	4,020.3
EQUITY			
Called up share capital		147.2	147.0
Share premium		609.8	606.4
Foreign currency translation reserve		(249.3)	(205.7)
Hedge reserve		569.9	401.6
Other reserves		740.9	740.9
Retained earnings		1,336.4	2,305.8
Equity attributable to equity holders of the Company		3,154.9	3,996.0
Non-controlling interest		19.8	24.3
Total equity		3,174.7	4,020.3

Condensed statement of changes in equity

Year ended 31 December 2015

	Share capital $m	Share premium $m	Foreign currency translation reserve $m	Hedge Reserve $m	Other reserves $m	Retained earnings $m	Total $m	Non-controlling interest $m	Total Equity $m
At 1 January 2014	146.9	603.2	(155.1)	2.3	740.9	3,984.7	5,322.9	123.5	5,446.4
Loss for the year	–	–	–	–	–	(1,555.7)	(1,555.7)	(84.2)	(1,639.9)
Hedges, net of tax	–	–	–	399.3	–	–	399.3	–	399.3
Currency translation adjustments	–	–	(50.6)	–	–	–	(50.6)	–	(50.6)
Issue of employee share options	0.1	3.2	–	–	–	–	3.3	–	3.3
Vesting of PSP shares	–	–	–	–	–	(0.4)	(0.4)	–	(0.4)
Share-based payment charges	–	–	–	–	–	59.5	59.5	–	59.5
Dividends paid	–	–	–	–	–	(182.3)	(182.3)	–	(182.3)
Distribution to non-controlling interests	–	–	–	–	–	–	–	(15.0)	(15.0)
At 1 January 2015	147.0	606.4	(205.7)	401.6	740.9	2,305.8	3,996.0	24.3	4,020.3
Loss for the year	–	–	–	–	–	(1,034.8)	(1,034.8)	(2.1)	(1,036.9)
Hedges, net of tax	–	–	–	168.3	–	–	168.3	–	168.3
Currency translation adjustments	–	–	(43.6)	–	–	–	(43.6)	–	(43.6)
Issue of employee share options	0.2	3.4	–	–	–	–	3.6	–	3.6
Vesting of PSP shares	–	–	–	–	–	(1.9)	(1.9)	–	(1.9)
Share-based payment charges	–	–	–	–	–	67.3	67.3	–	67.3
Dividends paid	–	–	–	–	–	–	–	–	–
Distribution to non-controlling interests	–	–	–	–	–	–	–	(2.4)	(2.4)
At 31 December 2015	147.2	609.8	(249.3)	569.9	740.9	1,336.4	3,154.9	19.8	3,174.7

1. *The foreign currency translation reserve represents exchange gains and losses arising on translation of foreign currency subsidiaries, monetary items receivable from or payable to a foreign operation for which settlement is neither planned nor likely to occur, which form part of the net investment in a foreign operation, 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 and the treasury shares reserve which represents the cost of shares in Tullow Oil plc purchased in the market and held by the Tullow Oil Employee Trust to satisfy awards held under the Group's share incentive plans.*

Condensed consolidated cash flow statement

Year ended 31 December 2015

	Notes	2015 $m	2014 $m
Cash flows from operating activities			
Loss before taxation		(1,297.3)	(2,047.4)
Adjustments for:			
Depletion, depreciation and amortisation		580.1	621.8
Loss on disposal		56.5	482.4
Goodwill impairment		53.7	132.8
Exploration costs written off	9	748.9	1,657.3
Impairment of property, plant and equipment	10	406.0	595.9
Provision for onerous service contracts	13	185.5	–
Provision for inventory		22.2	–
Decommissioning expenditure	13	(40.8)	(20.4)
Share-based payment charge		48.7	39.5
Loss/(gain) on hedging instruments		58.8	(50.8)
Finance revenue		(4.2)	(9.6)
Finance costs		149.0	143.2
Operating cash flow before working capital movements		967.1	1,544.7
(Increase)/decrease in trade and other receivables		(26.5)	29.9
Decrease in inventories		9.0	61.0
Increase/(decrease) in trade payables		366.5	(119.6)
Cash flows from operating activities		1,316.1	1,516.0
Income taxes received / (paid)		34.9	(34.2)
Net cash from operating activities		1,351.0	1,481.8
Cash flows from investing activities			
Proceeds from disposals		55.8	21.3
Purchase of intangible exploration and evaluation assets		(647.6)	(1,255.1)
Purchase of property, plant and equipment		(1,464.8)	(1,098.3)
Interest received		4.2	4.6
Net cash used in investing activities		(2,052.4)	(2,327.5)
Cash flows from financing activities			
Net proceeds from issue of share capital		3.5	3.3
Debt arrangement fees		(25.7)	(22.2)
Repayment of bank loans		(191.8)	(1,202.1)
Drawdown of bank loan		1,168.8	1,749.8
Issue of senior loan notes		–	650.0
Repayment of obligations under finance leases		(3.3)	(1.1)
Finance costs paid		(203.6)	(172.9)
Dividends paid		–	(182.3)
Distribution to non controlling interests		(2.4)	(15.0)
Net cash generated by financing activities		745.5	807.5
Net increase/(decrease) in cash and cash equivalents		44.1	(38.2)
Cash and cash equivalents at beginning of year		319.0	352.9
Cash transferred to held for sale		–	16.2
Foreign exchange loss		(7.4)	(11.9)
Cash and cash equivalents at end of year		355.7	319.0

Notes to the preliminary financial statements

Year ended 31 December 2015

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 2016.

The financial information for the year ended 31 December 2015 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 2014 have been delivered to the Registrar of Companies and those for 2015 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 2014. 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 2015, however these have not had a material impact on the accounting policies, methods of computation or presentation applied by the Group.

2. Loss per Share

The calculation of basic loss per share is based on the loss for the year after taxation attributable to equity holders of the parent of $1,034.8 million (2014: $1,555.7 million, loss) and a weighted average number of shares in issue of 911.3 million (2014: 910.1 million).

The calculation of diluted loss per share is based on the loss for the year after taxation as for basic earnings per share. The number of shares outstanding, however, is adjusted to show the potential dilution if employee share options are converted into ordinary shares. The weighted average number of ordinary shares is increased by 25.1 million (2014: 13.3 million) in respect of employee share options, resulting in a diluted weighted average number of shares of 936.4 million (2014: 923.4 million).

3. Dividends

In view of current capital allocation priorities, the Board is again recommending that no dividend is paid. At a time when Tullow is focusing on financial flexibility and cost reductions, the Board believes that Tullow and its shareholders are better served by retaining these funds in the business.

4. 2015 Annual Report and Accounts

The Annual Report and Accounts will be mailed on 15 March 2016 only to those shareholders who have elected to receive it. Otherwise, shareholders will be notified that the Annual Report and Accounts is available on the 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.

5. Annual General Meeting

Tullow's AGM will take place on 28 April 2016 at 12pm at Tullow Oil plc, Building 9 Chiswick Park, 566 Chiswick High Road, London, W4 5XT.

6. Segmental reporting

During 2015 the Group reorganised its operational 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 three new business delivery teams comprising: West Africa (including non-operated producing 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, profit and certain asset and liability information regarding the Group's reportable business segments for the years ended 31 December 2015 and 31 December 2014. The table for the year ended 31 December 2014 has been restated to reflect the new reportable segments of the business.

	West Africa $m	East Africa $m	New Ventures $m	Unallocated $m	Total $m
2015 Sales revenue by origin	1,606.6	–	–	–	1,606.6
Segment result	(189.7)	(28.3)	(461.2)	(123.6)	(802.8)
Loss on disposal of other assets					(56.5)
Unallocated corporate expenses					(234.4)
Operating Loss					(1,093.7)
Loss on hedging instruments					(58.8)
Finance revenue					4.2
Finance costs					(149.0)
Loss before tax					(1,297.3)
Income tax credit					260.4
Loss after tax					(1,036.9)
Total assets	7,510.5	2,601.6	1,011.2	224.5	11,347.8
Total liabilities	(3,085.8)	(341.4)	(331.8)	(4,414.1)	(8,173.1)
Other segment information					
Capital expenditure:					
Property, plant and equipment	1,245.0	0.5	1.5	11.2	1,258.2
Intangible exploration and evaluation assets	23.1	399.6	203.6	–	626.3
Depletion, depreciation and amortisation	(553.2)	(1.1)	(1.2)	(24.6)	(580.1)
Impairment of property, plant and equipment	(406.0)	–	–	–	(406.0)
Exploration costs written off	(380.0)	(28.3)	(340.6)	–	(748.9)
Goodwill impairment	–	–	(53.7)	–	(53.7)

6. Segmental reporting contd.

	West Africa $m	East Africa $m	New Ventures $m	Unallocated $m	Total $m
2014					
Sales revenue by origin	2,205.2	–	7.7	–	2,212.9
Segment result	371.8	0.8	(1,656.1)	(6.3)	(1,289.8)
Loss on disposal of oil and gas assets					(482.4)
Unallocated corporate expenses					(192.4)
Operating loss					(1,964.6)
Gain on hedging instruments					50.8
Finance revenue					9.6
Finance costs					(143.2)
Loss before tax					(2,047.4)
Income tax credit					407.5
Loss after tax					(1,639.9)
Total assets	7,454.2	2,354.7	1,397.3	215.5	11,421.7
Total liabilities	(3,285.9)	(267.6)	(588.5)	(3,259.4)	(7,401.4)
Other segment information					
Capital expenditure:					
Property, plant and equipment	1,463.1	1.6	11.0	59.6	1,535.3
Intangible exploration and evaluation assets	181.9	555.8	667.8	–	1,405.5
Depletion, depreciation and amortisation	(577.1)	(0.9)	(1.2)	(42.6)	(621.8)
Impairment of property, plant and equipment	(592.4)	–	(3.5)	–	(595.9)
Exploration costs written off	(134.6)	0.8	(1,523.5)	–	(1,657.3)
Goodwill impairment	–	–	(132.8)	–	(132.8)

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

7. Operating loss

	Notes	2015 $m	2014 $m
Cost of sales			
Operating costs		406.3	511.5
Depletion and amortisation of oil and gas assets	10	551.2	572.2
Underlift, overlift and oil stock movements		(1.5)	27.1
Share-based payment charge included in cost of sales		0.8	1.6
Other cost of sales		58.5	4.3
Total cost of sales		1,015.3	1,116.7
Administrative expenses			
Share-based payment charge included in administrative expenses		47.9	37.9
Depreciation of other fixed assets	10	28.9	49.6
Relocation costs associated with simplification project		5.9	–
Other administrative costs		110.9	104.9
Total administrative expenses		193.6	192.4
Restructuring costs	13	40.8	–

8. Taxation on loss on ordinary activities

a. Analysis of credit in period

The tax credit comprises:

	2015 $m	2014 $m
Current tax		
UK corporation tax	(3.5)	(61.5)
Foreign tax	94.9	(70.0)
Total corporate tax	91.4	(131.5)
UK petroleum revenue tax	(0.3)	4.8
Total current tax	91.1	(126.7)
Deferred tax		
UK corporation tax	6.9	(199.7)
Foreign tax	(354.0)	(81.4)
Total deferred corporate tax	(347.1)	(281.1)
Deferred UK petroleum revenue tax	(4.4)	0.3
Total deferred tax	(351.5)	(280.8)
Total tax credit	(260.4)	(407.5)

b. Factors affecting tax credit for period

The change in tax credit in 2015 is driven by deferred tax credits associated with exploration write-offs of $276.5 million (2014: $397.9 million) and impairments of $49.1 million (2014: $174.9 million).

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 current tax credit shown above and the amount calculated by applying the standard rate of UK corporation tax applicable to UK profits of 20% (2014: 21%) to the loss before tax is as follows:

	2015 $m	2014 $m
Group loss on ordinary activities before tax	(1,297.3)	(2,047.4)
Tax on Group loss on ordinary activities at the standard UK corporation tax rate of 20% (2014: 21%)	(259.5)	(430.0)
Effects of:		
Expenses not deductible for tax purposes	212.4	287.0
Goodwill impairment	10.7	27.9
PSC income not subject to corporation tax	(28.5)	(5.9)
Net losses not recognised	15.8	104.7
Petroleum revenue tax (PRT)	(4.4)	5.4
UK corporation tax deductions for current PRT	2.2	(3.3)
Utilisation of tax losses not previously recognised	–	(56.1)
Adjustments relating to prior years	(14.9)	(7.1)
Adjustments to deferred tax relating to change in tax rates	(1.0)	–
Income taxed at a different rate	(297.3)	(313.0)
Uganda capital gains tax	108.2	–
Tax incentives for investment	(4.1)	(17.1)
Group total tax credit for the year	(260.4)	(407.5)

8. Taxation on loss on ordinary activities contd.

The Group's profit before taxation will continue to arise in jurisdictions where the effective rate of taxation differs from that in the UK. 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 $1,802.0 million (2014: $1,642.1 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. The Group has recognised $55.7 million in deferred tax assets in relation to taxable losses (2014: $72.0 million); this is disclosed net of a deferred tax liability in respect of capitalised interest.

No deferred tax liability is recognised on temporary differences of $8.5 million (2014: $21.2 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 2015 $42.3 million (2014: $91.0 million) of tax has been recognised through other comprehensive income of which $43.2 million (2014: $89.5 million) is current and $0.9 million (2014: $1.5 million) is deferred tax relating to charges on cash flow hedges arising in the year.

Current tax assets

As at 31 December 2015, current tax assets were $127.6 million (2014: $221.6 million) of which $55.0 million (2014: $155.9 million) relates to Norway, where 78% of exploration expenditure is refunded as a tax refund in the following year and $47.7 million (2014: $47.7 million) relates to a tax overpayment in Ghana.

9. Intangible exploration and evaluation assets

	2015 $m	2014 $m
At 1 January	3,660.8	4,148.3
Additions	626.3	1,405.5
Disposals	(5.2)	(26.8)
Amounts written off	(748.9)	(1,657.3)
Amounts written off previously classified held for sale	–	(5.1)
Write-off associated with Norway contingent consideration	–	(88.8)
Transfer to assets held for sale	–	(13.8)
Transfer to property, plant and equipment	(63.6)	–
Currency translation adjustments	(69.4)	(101.2)
At 31 December	3,400.0	3,660.8

Included within 2015 additions is $49.7 million of capitalised interest (2014: $47.8 million). The Group only capitalises interest in respect of intangible exploration and evaluation assets where it is considered that development is highly likely and advanced appraisal and development is ongoing.

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

	Rationale for 2015 write-off	2015 Current year expenditure written off $m	2015 Prior year expenditure written off $m	2015 Post-tax write off $m	2015 Pre-tax write off $m	2014 Current year expenditure written off $m	2014 Prior year expenditure written off $m	2014 Post-tax write off $m	2014 Pre-tax write off $m
Côte d'Ivoire	b	2.9	–	2.9	2.9	2.7	55.3	58.0	58.0
Ethiopia	c	4.8	34.9	39.7	39.7	65.1	–	65.1	65.1
French Guiana	c	0.3	–	0.3	0.3	(1.3)	344.4	343.1	363.4
Gabon	a, b, c	3.5	8.5	12.0	21.3	26.9	6.4	33.3	54.0
Ghana	b	0.4	–	0.4	0.4	0.5	19.9	20.4	20.4
Guinea	c	6.0	54.3	60.3	60.3	–	–	–	–
Greenland	c	0.2	38.5	38.7	38.7	–	–	–	–
Kenya	a	28.3	–	28.3	28.3	0.6	–	0.6	0.6
Netherlands	c	–	185.7	185.7	371.3	–	–	–	–
Norway	a, b	11.3	8.9	20.2	92.2	28.1	52.3	80.4	366.6
Madagascar	c	1.5	10.7	12.2	12.2	–	–	–	–
Mauritania	b	7.3	–	7.3	7.3	199.6	368.6	568.2	621.4
Mozambique	b	4.6	–	4.6	4.6	(6.2)	–	(6.2)	(6.2)
Suriname	a	27.8	1.0	28.8	28.8	–	–	–	–
Uganda	n/a	–	–	–	–	(1.5)	–	(1.5)	(1.5)
Other	a, b, c	11.9	–	11.9	15.2	48.7	7.0	55.7	62.2
New ventures		19.1	–	19.1	25.4	42.3	–	42.3	53.3
Total write-off		129.9	342.5	472.4	748.9	405.5	853.9	1,259.4	1,657.3

a. Current year unsuccessful drilling results
b. Licence relinquishments
c. Review of forward work programme in light of capital re-allocation to development projects and current low oil and gas price environment.

10. Property, plant and equipment

	2015 Oil and gas assets $m	2015 Other fixed assets $m	2015 Total $m	2014 Oil and gas assets $m	2014 Other fixed assets $m	2014 Total $m
Cost						
At 1 January	9,240.3	283.7	9,524.0	8,692.4	221.4	8,913.8
Additions	1,235.1	23.1	1,258.2	1,454.7	80.6	1,535.3
Disposals	(6.2)	(3.6)	(9.8)	(601.3)	0.1	(601.2)
Transfer to assets held for sale	–	–	–	(177.2)	–	(177.2)
Transfer from intangible assets	63.6	–	63.6	–	–	–
Currency translation adjustments	(92.9)	(13.7)	(106.6)	(128.3)	(18.4)	(146.7)
At 31 December	10,439.9	289.5	10,729.4	9,240.3	283.7	9,524.0
Depreciation, depletion and amortisation						
At 1 January	(4,489.1)	(147.9)	(4,637.0)	(3,942.3)	(108.6)	(4,050.9)
Charge for the year (note 7)	(551.2)	(28.9)	(580.1)	(572.2)	(49.6)	(621.8)
Impairment loss	(467.2)	–	(467.2)	(595.9)	–	(595.9)
Impairment reversal	61.2	–	61.2	–	–	–
Disposal	6.4	3.6	10.0	448.0	(0.1)	447.9
Transfer to assets held for sale	–	–	–	73.3	–	73.3
Currency translation adjustments	79.9	8.2	88.1	100.0	10.4	110.4
At 31 December	(5,360.0)	(165.0)	(5,525.0)	(4,489.1)	(147.9)	(4,637.0)
Net book value at 31 December	5,079.9	124.5	5,204.4	4,751.2	135.8	4,887.0

The 2015 additions include capitalised interest of $110.4 million in respect of the TEN development project (2014: $72.8 million). The carrying amount of the Group's oil and gas assets includes an amount of $27.4 million (2014: $33.0 million) in respect of assets held under finance leases. Other fixed assets include leasehold improvements, motor vehicles and office equipment. The currency translation adjustments arose due to the movement against the Group's presentation currency, USD, of the Group's UK and Dutch assets which have functional currencies of GBP and EUR respectively.

	Trigger for 2015 impairment	2015 Impairment $m	Discount rate assumption	Short-term price assumption[d]	Mid-term price assumption	Long-term price assumption
CMS GCU[e]	a	87.5	10%	2yr forward curve	n/a	42.5p/th
Thames GCU[e]	b	(44.2)	10%	2yr forward curve	n/a	42.5p/th
Netherlands CGU[e]	a	28.7	10%	2yr forward curve	n/a	0.53€/th
Limande CGU[f] (Gabon)	a	(0.2)	13%	2yr forward curve	$70/bbl	$90/bbl
Niungo CGU[f] (Gabon)	a	21.1	15%	2yr forward curve	$70/bbl	$90/bbl
Oba CGU[f] (Gabon)	a	13.7	13%	2yr forward curve	$70/bbl	$90/bbl
Tchatamba (Gabon)	c	(16.8)	13%	2yr forward curve	$70/bbl	$90/bbl
M'boundi (Congo)	a	65.9	12%	2yr forward curve	$70/bbl	$90/bbl
Equatorial Guinea CGU[g]	a	16.3	10%	2yr forward curve	$70/bbl	$90/bbl
TEN (Ghana)	a	228.5	10%	2yr forward curve	$70/bbl	$90/bbl
Chinguetti (Mauritania)	a	5.5	10%	2yr forward curve	$70/bbl	$90/bbl
Impairment before tax		406.0				
Associated deferred tax credit		(49.1)				
Impairment after tax		356.9				

a. Reduction in estimated oil and gas forward curve and long-term price (refer to accounting policy on significant estimates)
b. Reduction in decommissioning estimate
c. Increase in 2P reserves
d. UK NBP gas forward curve and Bloomberg Brent forward curve as at 31 December 2015. All pricing assumptions have been adjusted for individual field and contract differentials
e. The fields in the UK and the Netherlands are grouped into two CGUs as all fields within those countries share critical gas infrastructure
f. The Limande and Niungo CGUs in Gabon comprise a number of fields which share export infrastructure
g. The Ceiba and Okume fields in Equatorial Guinea form a single CGU as they share export infrastructure

All impairment assessments are prepared on a Value In Use basis using discounted future cash flows based on 2P reserves profiles. An 1% increase in the discount rates used would trigger a further impairment of $161.9 million and a $10/bbl reduction to the whole oil price deck would trigger a further impairment of $784.3 million.

11. Other assets

	2015 $m	2014 $m
Non-current		
Amounts due from joint venture partners	161.8	57.0
Uganda VAT recoverable	50.3	50.6
Other non-current assets	11.3	12.1
	223.4	119.7
Current		
Amounts due from joint venture partners	584.4	633.2
Underlifts	2.4	–
Prepayments	77.9	82.6
VAT recoverable	9.2	49.8
Other current assets	89.3	136.7
	763.2	902.3

The increase in amounts due from joint venture partners relates to the increase in operated current liabilities, which are recorded gross with the corresponding debit recognised as an amount due from joint venture partners, in Kenya and Ghana.

12. Trade and other payables

Current liabilities

	2015 $m	2014 $m
Trade payables	24.0	126.5
Other payables	61.2	104.6
Overlifts	3.7	15.6
Accruals	993.3	734.8
VAT and other similar taxes	26.9	92.1
Current portion of finance lease	1.5	1.3
	1,110.6	1,074.9

Payables related to operated joint ventures (primarily related to Ghana and Kenya) are recorded gross with the debit representing the partners' share recognised in amounts due from joint venture partners (note 11). The decrease in trade payables and the decrease in other payables predominantly represent timing differences.

Non-current liabilities

	2015 $m	2014 $m
Other non-current liabilities	72.8	57.0
Non-current portion of finance lease	26.5	28.1
	99.3	85.1

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

13. Provisions

Current Provisions

	2015 $m	2014 $m
Provision for onerous service contracts	185.5	–
Provision for restructuring costs	1.5	–
	187.0	–

Due to the reduction in planned future work programmes the Group has identified a number of onerous service contracts. The expected unutilised capacity has been provided for in 2015 resulting in an income statement charge of $185.5 million (2014: $nil million).

During 2015 the Group has incurred $44.9 million in respect of restructuring costs. After recharges to joint venture partners, the income statement charge for restructuring costs is $40.8 million. As at 31 December 2015 $1.5 million is yet to be incurred and has been recorded as a provision.

13. Provisions contd.

Non-current Provisions

	Decommissioning 2015 $m	Other provisions 2015 $m	Total 2015 $m	Decommissioning 2014 $m	Other provisions 2014 $m	Total 2014 $m
At 1 January	1,192.9	67.5	1,260.4	841.5	147.7	989.2
New provisions and changes in estimates	(147.4)	(9.9)	(157.3)	454.9	(82.1)	372.8
Transfers to liability held for sale	–	–	–	(14.8)	–	(14.8)
Disposals	0.8	0.3	1.1	(54.6)	–	(54.6)
Decommissioning payments	(40.8)	–	(40.8)	(20.4)	–	(20.4)
Unwinding of discount	28.3	0.1	28.4	22.4	16.9	39.3
Currency translation adjustment	(25.0)	(1.7)	(26.7)	(36.1)	(15.0)	(51.1)
At 31 December	1,008.8	56.3	1,065.1	1,192.9	67.5	1,260.4

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	2015 $m	2014 $m
Congo	2%	3%	2027	15.2	13.4
Cote d'Ivoire	2%	3%	2026	53.3	52.7
Equatorial Guinea	2%	3%	2028-2029	126.2	175.8
Gabon	2%	3%	2021-2034	61.0	107.1
Ghana	2%	3%	2034-3036	257.7	278.3
Mauritania	2%	3%	2017	121.4	113.3
Netherlands	2%	3%	2020-2036	90.5	100.7
UK	2%	3%	2014-2018	283.5	351.6
				1,008.8	1,192.9

Other provisions include a liability acquired through the acquisition of Spring Energy which is contingent in terms of timing and amount on the development of the PL407 licence in Norway. Other provisions also include the contingent consideration in respect of the Spring acquisition.

14. 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 2015	307.6	226.4	–	–	–	–	307.6	226.4	345.3
Revisions	3.0	6.8	–	–	–	–	3.0	6.8	4.1
Transfer from contingent resources	0.9	–	–	–	–	–	0.9	–	0.9
Disposals	–	(10.0)	–	–	–	–	–	(10.0)	(1.7)
Production	(23.9)	(17.4)	–	–	–	–	(23.9)	(17.4)	(26.8)
31 December 2015	287.6	205.8	–	–	–	–	287.6	205.8	321.8
CONTINGENT RESOURCES									
1 January 2015	106.8	993.7	531.6	12.4	101.5	4.2	739.9	1,010.3	908.3
Revisions	9.9	(233.6)	79.1	30.2	–	–	89.0	(203.4)	55.1
Additions	–	–	18.1	–	–	–	18.1	–	18.1
Disposals	–	(35.2)	–	–	–	–	–	(35.2)	(5.9)
Transfers to commercial reserves	(0.9)	–	–	–	–	–	(0.9)	–	(0.9)
31 December 2015	115.8	724.9	628.8	42.6	101.5	4.2	846.1	771.7	974.7
TOTAL									
31 December 2015	403.4	930.7	628.8	42.6	101.5	4.2	1,133.7	977.5	1,296.5

1. Proven and Probable Commercial Reserves are based on a Group reserves report produced 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.
2. Proven and Probable Contingent Resources are based on a Group reserves report produced 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 relate to Jubilee, Equatorial Guinea and Gabon.
4. The West Africa disposals relate to the L&Q block in the Netherlands and farm-down of the Vincent discovery
5. The West Africa revision to gas contingent resources relates to the relinquishment of the Pelican field in Mauritania.
6. East Africa additions to oil contingent resources relate to Etom in Kenya.
7. East Africa revision to contingent resources relate to Kenya and Uganda.

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 299.1 mmboe at 31 December 2015 (31 December 2014: 321.0 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 over 120 exploration and production licences across 22 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 London Presentation and a number of events for the financial community.

09.00 GMT - UK/European conference call (and simultaneous video webcast)

To access the call please dial the appropriate number below shortly before the call and ask for the Tullow Oil plc conference call. A replay facility will be available from approximately noon on 10 February until 17 February. The telephone numbers and access codes are:

Live event		Replay facility available from Noon	
UK Participants	+44 (0) 20 3427 1903	UK Participants	+44 (0) 20 3427 0598
Irish Participants	+353 (0)1 2465602	Irish Participants	+353 (0) 1 4860902
		Access Code	4375795

To join the live video webcast, or play the on-demand version which will be available from noon on 10 February, you will need to have either Real Player or Windows Media Player installed on your computer.

15:00 EST - US 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.

Live Event			
Domestic Toll Free	1877 280 2296	Access code	4439098
Toll	+1212 444 0896		

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