Financial statements

Consolidated financial statements of the BP group

Independent auditor's report on the Annual Report and Accounts to the members of BP p.l.c.

Opinion on financial statements

In our opinion:

- the financial statements give a true and fair view of the state of the group's and of the parent company's affairs as at 31 December 2015 and of the group's loss for the year then ended;
- the group financial statements have been properly prepared in accordance with IFRS as adopted by the European Union;
- the parent company financial statements have been properly prepared in accordance with United Kingdom generally accepted accounting practice including FRS 101; and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006 and, as regards the group financial statements, Article 4 of the IAS Regulation.

Separate opinion in relation to IFRS as issued by the International Accounting Standards Board

As explained in Note 1 to the consolidated financial statements, the group in addition to applying IFRS as adopted by the European Union, has also applied IFRS as issued by the International Accounting Standards Board (IASB). In our opinion the consolidated financial statements comply with IFRS as issued by the IASB.

What we have audited

We have audited the financial statements of BP p.l.c. for the year ended 31 December 2015 which comprise:

Group	Parent company
Group balance sheet as at 31 December 2015.	Balance sheet as at 31 December 2015.
Group income statement for the year then ended.	Cash flow statement for the year then ended.
Group statement of comprehensive income for the year then ended.	Statement of changes in equity for the year then ended.
Group statement of changes in equity for the year then ended.	Related Notes 1 to 15 to the financial statements.
Group cash flow statement for the year then ended.	
Related Notes 1 to 37 to the financial statements.	

The financial reporting framework that has been applied in the preparation of the group financial statements is applicable law and International Financial Reporting Standards (IFRS) as adopted by the European Union. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom accounting standards (United Kingdom generally accepted accounting practice) including FRS 101.

Our assessment of risks of material misstatement

We identified the risks of material misstatement described below as those that had the greatest effect on our overall audit strategy, the allocation of resources in the audit and the direction of the efforts of the audit team. In addressing these risks, we have performed the procedures below which were designed in the context of the financial statements as a whole and, consequently, we do not express any opinion on these individual areas. These matters are unchanged from those we reported in our 2014 audit opinion.

Risk	Our response to the risk	What we concluded to the Audit Committee
The determination of the liabilities, contingent liabilities and disclosures arising from the significant uncertainties related to the Gulf of Mexico oil spill (as described on page 70 of the report of the audit committee and Notes 1 and 2 of the financial statements). On 2 July 2015, the group announced it had reached agreements in principle with the United States federal government and five Gulf states to settle all federal and state claims arising from the incident. The proposed Consent Decree to resolve all United States and Gulf states natural resource damage claims and Clean Water Act penalty claims is awaiting court approval. The United States is expected to file a motion with the court to enter the Consent Decree as a final settlement around the end of March, which the court will then consider. Although there is still risk, the agreements in principle have significantly reduced the uncertainty associated with this element of the liability determination for 2015. Following the agreements in principle, we concluded the remaining uncertainties were no longer fundamental to a user's understanding of the financial statements and therefore we have removed the Emphasis of Matter from our 2015 audit opinion. There continues to be uncertainty regarding the outcome of Plaintiffs' Steering Committee ('PSC') settlements, the most substantial category being business economic loss claims. The 8 June 2015 deadline for claims resulted in a significant number of claims received, which have not yet been processed and quantified. Management concluded that a reliable estimation of the expected liability still cannot be made at 31 December 2015.	For the Gulf of Mexico oil spill the primary audit engagement team performed the following audit procedures. • We walked through and tested the controls designed and operated by the group relating to the liability accounts for the Gulf of Mexico oil spill. • We met with the group's legal team to understand developments across all of the Gulf of Mexico oil spill matters and their status. We discussed legal developments with the group's external lawyers and read determinations and judgments made by the courts. • We reviewed the agreements in principle, verifying that specific matters were accurately reflected in the group's accounting and disclosures. • With regard to PSC settlements, we engaged EY actuarial experts to consider the analysis of available claims data undertaken by management. We corroborated the data used in respect of all claim categories, with specific regard to business economic loss, this being the most complex to estimate. Our testing included understanding and verifying trends in the actuarial models, considering the approach in respect of all claim categories which included comparing with prior periods. • We considered the accounting treatment of the liabilities, contingent liabilities and disclosures under IFRS criteria, to conclude whether these were appropriate in all the circumstances.	Based on our procedures we are satisfied that the amounts provided by management are appropriate. We are satisfied that management is unable to determine a reliable estimate for certain obligations as disclosed in Note 2 of the financial statements. Given the agreements in principle signed on 2 July 2015 we consider it appropriate that the Emphasis of Matter is no longer required in our audit opinion.

This page does not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Risk	Our response to the risk	What we concluded to the Audit Committee
The significant decrease in current and future oil and gas prices during 2015 and the impact this has had on the carrying value of the group's Upstream assets (as described on page 69 of the report of the audit committee and Note 1 of the financial statements). Declines in commodity prices have had a significant effect on the carrying value of the group's assets, as evidenced by the impairments recognized in the 2015 financial statements and in the prior year. The principal risk is in relation to management's assessment of future cash flows, which are used to project the recoverability of tangible and intangible assets.	We extended the scope of our original planned procedures to address the changing risk. This included further use of EY valuation experts in critically assessing and corroborating the revised assumptions used in impairment testing, the most significant of these being future market oil and gas prices and discount rates. We also focused on reserves and resources volumes, as described elsewhere in our report. In addressing this risk, audit procedures were performed by the component teams at each of the group's 14 Upstream locations scoped-in for the audit of asset impairment and by the primary audit engagement team for the remaining assets identified at risk of impairment. • We walked through and tested the controls designed and operated by the group relating to the assessment of the carrying value of tangible and intangible assets. • We examined the methodology used by management to assess the carrying value of tangible and intangible assets assigned to cash-generating units, to determine its compliance with accounting standards and consistency of application. • We corroborated estimates of future cash flows and challenged whether these were appropriate in light of future price assumptions and the cost budgets. We performed sensitivity analyses over inputs to the cash flow models. • Together with EY valuation experts we assessed specific inputs to the determination of the discount rate, including the risk-free rate and country risk rates, along with gearing and cost of debt. Such inputs were benchmarked against risk rates in international markets in which the group operates. • We performed procedures over the completeness of the impairment charge and exploration write-offs, also validating that base data used in the impairment models agreed to the underlying books and records.	BP's oil and gas price assumptions are comparable to the range seen within the industry at this time. The reduction in the pre-tax discount rate from 12% to 11% and the post-tax discount rate from 8% to 7% are within the range of our expectation. Based on our procedures, we believe the impairment charge is appropriate. Based on our procedures on the exploration portfolio we consider the write-offs were properly recorded and remaining carrying values are appropriate.
The estimate of oil and gas reserves and resources has a significant impact on the financial statements, particularly impairment testing and depreciation, depletion and amortization ('DD&A') charges (as described on page 69 of the report of the audit committee and Note 1 of the financial statements). The estimation of oil and natural gas reserves and resources is a significant area of judgement due to the technical uncertainty in assessing quantities and complex contractual arrangements dictating the group's share of reportable volumes. Reserves and resources are also a fundamental indicator of the future potential of the group's performance.	Audit procedures were performed by the component teams at each of the group's 14 Upstream locations scoped-in for the audit of reserves and resources and by the primary audit engagement team. • We tested the group's controls over their internal certification process for technical and commercial experts who are responsible for reserves and resources estimation. • We assessed the competence and objectivity of these experts, to satisfy ourselves they were appropriately qualified to carry out the volumes estimation. • We confirmed that significant changes in reserves and resources were made in the appropriate period, and in compliance with the Discovered Resources Management Policy ('DRM-P'). We gave specific consideration to BP's reported share of reserves in joint arrangements and associates, including Rosneft. • Where volumetric movements had a material impact on the financial statements, we validated these volumes against underlying information and documentation as required by the DRM-P, along with checking that assumptions used to estimate reserves and resources were made in compliance with relevant regulations. • We validated that the updated reserves and resources estimates were included appropriately in the group's consideration of impairment and in accounting for DD&A.	Based on our procedures we consider that the reserves estimations are reasonable for use in the impairment testing and calculation of DD&A.
Unauthorized trading activity within the integrated supply & trading function and the potential impact on revenue (as described on page 69 of the report of the audit committee and Note 1 of the financial statements). Unauthorized trading activity is a fraud risk associated with a potential deliberate misstatement of the group's trading positions or mis-marking of positions with an intention to: • minimize trading losses. • maximize trading profits. • understate profits or move profits to subsequent periods when bonus ceilings have already been reached, to maximize individual bonuses across financial years. These acts would lead to an overstatement or understatement of the group's revenue and profits.	Audit procedures on revenue and trading were performed by component teams and the primary audit engagement team at 7 locations across the US, UK and Singapore. • We walked through and tested the controls designed and operated by the group over unauthorized trading activity. • Using analytics software we identified trades with the highest risk of unauthorized activity so as to focus our testing on these trades. • We obtained confirmations directly from third parties for a sample of trades. • We verified the fair value of a sample of derivatives using contract and external market prices. • We tested the completeness of the amounts recorded in the financial statements through performing procedures to detect unrecorded liabilities as well as detailed cut-off procedures around sales, purchases, trade receivables and trade payables.	Based on our procedures we identified no matters to report to the Audit Committee.

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Risk	Our response to the risk	What we concluded to the Audit Committee
The current geopolitical environment in Russia and the existence of US and EU economic sanctions may impact BP's ability to exercise significant influence over Rosneft and the consequent accounting for the group's interest in Rosneft using the equity method (as described on page 69 of the report of the audit committee and Notes 1 and 16 of the financial statements). Geopolitical developments (such as further sanctions) may present changes which could diminish the ability of the group to exert significant influence, through diminished participation in the financial and operating policy decisions of Rosneft.	For the Rosneft operating segment the primary audit engagement team performed the following audit procedures. • We assessed the impact of sanctions imposed by the US and EU to determine the effect on the group's ability to exercise significant influence over Rosneft. We did this through discussion with the group's legal team and through observing the interaction between BP and Rosneft. We verified the second BP-appointed director to the board of Rosneft and considered whether BP demonstrated significant influence under IFRS criteria. • We considered the adequacy of the financial and other information provided to BP to allow compliance with its reporting obligations, observing that appropriate review was completed by BP on the information reported. • We provided instructions to Rosneft's independent auditors who reported in accordance with our timetable and instructions.	Based on our procedures we are satisfied that the criteria in IFRS for equity accounting are met in respect of Rosneft and that the impact of sanctions extant at this time does not prevent the exercise of significant influence by BP.

The scope of our audit

Our assessment of audit risk, our evaluation of materiality and our allocation of performance materiality determine our audit scope for each entity within the group. Taken together, this enables us to form an opinion on the consolidated financial statements. We take into account size, risk profile, the organization of the group and effectiveness of group-wide controls, changes in the business environment and other factors such as recent internal audit results when assessing the level of work to be performed at each component.

In scoping the audit we reflect the group's structure (Upstream, Downstream, Rosneft, Other businesses and corporate and Gulf of Mexico oil spill), plus the group's functions. In assessing the risk of material misstatement to the group financial statements, and to ensure we had adequate quantitative coverage of significant accounts in the financial statements, we performed full or specific scope audit procedures over 47 components covering the UK, US, Angola, Azerbaijan, Germany, Russia, Singapore and the group functions, representing the principal business units within the group.

Of the 47 components selected, we performed an audit of the complete financial information of 9 components ("full scope components") which were selected based on their size or risk characteristics. For the remaining 38 components ("specific scope components"), we performed audit procedures on specific accounts within that component that we considered had the potential for the greatest impact on the significant accounts in the financial statements either because of the size of these accounts or their risk profile.

For the current year, the full scope components contributed 43% of the group's loss before tax, 41% of the group's revenue and 11% of the group's property, plant and equipment. The specific scope components contributed 29% of the group's revenue and 55% of the group's property, plant and equipment. The audit scope of these components may not have included testing of all significant accounts of the component but will have contributed to the coverage of significant accounts tested for the group. Of the 38 specific scope components, we instructed 7 of these locations to perform specified procedures over impairment of goodwill and other intangible assets, recoverability of certain receivables and the carrying value of certain investments held by the group.

The remaining components not subject to full or specific group scoping are not significant individually or in the aggregate. They include many small, low risk components and balances; each remaining component represents an average of 0.02% of the total group loss before tax and 0.04% of total group revenue. For these components, we performed other procedures, including evaluating and testing management's group wide controls across a range of geographies and segments, specifically testing the oversight and review controls that management has in place to ensure there are no material misstatements in these locations. We performed analytical and enquiry procedures to address the risk of residual misstatement on a segment-wide and component basis. We tested consolidation journals to identify the existence of any further risks of misstatement that could have been material to the group financial statements.

Changes from the prior year

In the current year we designed full and specific procedures for in-scope components, which represents a change from the prior year when specific scope components only, were included. This change did not result in a significant change in the level of procedures undertaken at locations.

Involvement with component teams

In establishing our overall approach to the group audit, we determined the type of work that needed to be undertaken at each of the components by us, as the primary audit engagement team, or by component auditors from other EY global network firms operating under our instruction. Of the 9 full scope components, audit procedures were performed on 5 of these directly by the primary audit engagement team. For the 38 specific scope components, audit procedures were performed on 18 directly by the primary audit engagement team. Where work was performed by component auditors, we determined the appropriate level of involvement to enable us to determine that sufficient audit evidence had been obtained as a basis for our opinion on the group as a whole.

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The group audit team continued to follow a programme of planned visits designed to ensure that the Senior Statutory Auditor or his designate visits significant locations to ensure the audit is executed and delivered in accordance with the planned approach and to confirm the quality of the audit work undertaken. During the current year's audit cycle, visits were undertaken by the primary audit engagement team to the component teams in the US, Angola, Azerbaijan, Germany and Russia. Part of the purpose of these visits is to confirm that appropriate procedures have been performed by the auditors of the components and that the significant audit areas were covered as communicated in the detailed audit instructions, including the risks of material misstatement as outlined above. The primary audit engagement team review included examining key working papers and conclusions where these related to areas of management and auditor judgement with specific focus on the risks detailed above. The primary audit engagement team also participated in the component teams' planning, during visits made earlier in the audit period. Telephone and video meetings were held with the auditors at locations which the primary audit engagement team did not visit in person. This, together with additional procedures performed at group level, gave us appropriate evidence for our opinion on the group financial statements.

One of the significant locations is Russia, which includes Rosneft, a material associate not controlled by BP. We were provided with appropriate access to Rosneft's auditor in order to ensure they had completed the procedures required by ISA 600 on the financial statements of Rosneft, used as the basis for BP's equity accounting.

Our application of materiality

We apply the concept of materiality in planning and performing the audit, in evaluating the effect of identified misstatements on the audit and in forming our audit opinion.

Materiality

The magnitude of an omission or misstatement that, individually or in the aggregate, could reasonably be expected to influence the economic decisions of the users of the financial statements. Materiality provides a basis for determining the nature and extent of our audit procedures.

We determined materiality for the group to be $0.5 billion (2014 $1 billion), which is 5.7% (2014 5%) of underlying replacement cost profit (as defined on page 258) before interest and taxation. We believe that underlying replacement cost profit before interest and taxation is the most appropriate measure upon which to calculate materiality, due to the fact it excludes the impact of both changes in crude oil and product prices and items disclosed as non-operating items that can significantly distort the group's results.

During the course of our audit, we re-assessed initial materiality in the context of the group's performance and this resulted in no change from our original assessment of materiality.

Performance materiality

The application of materiality at the individual account or balance level. It is set at an amount to reduce to an appropriately low level the probability that the aggregate of uncorrected and undetected misstatements exceeds materiality.

On the basis of our risk assessments, together with our assessment of the group's overall control environment, our judgement was that performance materiality was 75% (2014 75%) of our materiality, namely $375 million (2014 $750 million). We have set performance materiality at this percentage to reduce to an appropriately low level the probability that the aggregate of uncorrected and undetected misstatements exceeds materiality.

Audit work at component locations for the purpose of obtaining audit coverage over significant financial statement accounts is undertaken based on a percentage of total performance materiality. The performance materiality set for each component is based on the relative scale and risk of the component to the group as a whole and our assessment of the risk of misstatement at that component. In the current year, the range of performance materiality allocated to components was $75 million to $300 million (2014 $150 million to $640 million).

Reporting threshold

An amount below which identified misstatements are considered as being clearly trivial.

We agreed with the audit committee that we would report to them all uncorrected audit differences in excess of $25 million (2014 $50 million), which is set at 5% of materiality, as well as differences below that threshold that, in our view, warranted reporting on qualitative grounds.

We evaluate any uncorrected misstatements against both the quantitative measures of materiality discussed above and in light of other relevant qualitative considerations in forming our opinion.

Scope of the audit of the financial statements

An audit involves obtaining evidence about the amounts and disclosures in the financial statements sufficient to give reasonable assurance that the financial statements are free from material misstatement, whether caused by fraud or error. This includes an assessment of: whether the accounting policies are appropriate to the group's and the parent company's circumstances and have been consistently applied and adequately disclosed; the reasonableness of significant accounting estimates made by the directors; and the overall presentation of the financial statements. In addition, we read all the financial and non-financial information in the annual report to identify material inconsistencies with the audited financial statements and to identify any information that is apparently materially incorrect based on, or materially inconsistent with, the knowledge acquired by us in the course of performing the audit. If we become aware of any apparent material misstatements or inconsistencies we consider the implications for our report.

Respective responsibilities of directors and auditor

As explained more fully in the Statement of directors' responsibilities set out on page 93, the directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view. Our responsibility is to audit and express an opinion on the financial statements in accordance with applicable law and International Standards on Auditing (UK and Ireland). Those standards require us to comply with the Auditing Practices Board's Ethical Standards for Auditors.

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

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Opinion on other matters prescribed by the Companies Act 2006

In our opinion:

- the part of the Directors' remuneration report to be audited has been properly prepared in accordance with the Companies Act 2006; and
- the information given in the Strategic report and the Directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements.

Matters on which we are required to report by exception

ISAs (UK and Ireland) reporting	We are required to report to you if, in our opinion, financial and non-financial information in the annual report is: • materially inconsistent with the information in the audited financial statements; or • apparently materially incorrect based on, or materially inconsistent with, our knowledge of the group acquired in the course of performing our audit; or • otherwise misleading. In particular, we are required to report whether we have identified any inconsistencies between our knowledge acquired in the course of performing the audit and the directors' statement that they consider the annual report and accounts taken as a whole is fair, balanced and understandable and provides the information necessary for shareholders to assess the entity's position and performance, business model and strategy; and whether the annual report appropriately addresses those matters that we communicated to the audit committee that we consider should have been disclosed.	We have no exceptions to report.
Companies Act 2006 reporting	We are required to report to you if, in our opinion: • adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or • the parent company financial statements and the part of the Directors' remuneration report to be audited are not in agreement with the accounting records and returns; or • certain disclosures of directors' remuneration specified by law are not made; or • we have not received all the information and explanations we require for our audit.	We have no exceptions to report.
Listing Rules review requirements	We are required to review: • the directors' statement in relation to going concern, set out on page 94, and longer-term viability, set out on page 94; and • the part of the Corporate governance statement relating to the company's compliance with the provisions of the UK Corporate Governance Code specified for our review.	We have no exceptions to report.

Statement on the directors' assessment of the principal risks that would threaten the solvency or liquidity of the entity

ISAs (UK and Ireland) reporting	We are required to give a statement as to whether we have anything material to add or to draw attention to in relation to: • the directors' confirmation in the annual report that they have carried out a robust assessment of the principal risks facing the entity, including those that would threaten its business model, future performance, solvency or liquidity; • the disclosures in the annual report that describe those risks and explain how they are being managed or mitigated; • the directors' statement in the Directors' report (Directors' statements, page 94) about whether they considered it appropriate to adopt the going concern basis of accounting in preparing them, and their identification of any material uncertainties to the entity's ability to continue to do so over a period of at least twelve months from the date of approval of the financial statements; and • the directors' explanation in the annual report as to how they have assessed the prospects of the entity, over what period they have done so and why they consider that period to be appropriate, and their statement as to whether they have a reasonable expectation that the entity will be able to continue in operation and meet its liabilities as they fall due over the period of their assessment, including any related disclosures drawing attention to any necessary qualifications or assumptions.	We have nothing material to add or to draw attention to.

John C. Flaherty (Senior Statutory Auditor)
for and on behalf of Ernst & Young LLP, Statutory Auditor
London
4 March 2016

1. The maintenance and integrity of the BP p.l.c. web site is the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the web site.
2. Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

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Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

The board of directors and shareholders of BP p.l.c.

We have audited the accompanying group balance sheets of BP p.l.c. as of 31 December 2015 and 31 December 2014, and the related group income statement, group statement of comprehensive income, group statement of changes in equity and group cash flow statement for each of the three years in the period ended 31 December 2015. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the group financial position of BP p.l.c. at 31 December 2015 and 31 December 2014, and the group results of its operations and its cash flows for each of the three years in the period ended 31 December 2015, in accordance with International Financial Reporting Standards as adopted by the European Union and International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), BP p.l.c.'s internal control over financial reporting as of 31 December 2015, based on criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting and our report dated 4 March 2016 expressed an unqualified opinion.

/s/ Ernst & Young LLP
London, United Kingdom
4 March 2016

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Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

The board of directors and shareholders of BP p.l.c.

We have audited BP p.l.c.'s internal control over financial reporting as of 31 December 2015, based on criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting. BP p.l.c.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's report on internal control on page 244. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, BP p.l.c. maintained, in all material respects, effective internal control over financial reporting as of 31 December 2015, based on the UK Financial Reporting Council's Guidance.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the group balance sheets of BP p.l.c. as of 31 December 2015 and 2014, and the related group income statement, group statement of comprehensive income, group statement of changes in equity and group cash flow statement for each of the three years in the period ended 31 December 2015, and our report dated 4 March 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
London, United Kingdom
4 March 2016

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 4 March 2016, with respect to the group financial statements of BP p.l.c., and the effectiveness of internal control over financial reporting of BP p.l.c., included in this Annual Report and Form 20-F for the year ended 31 December 2015 in the following Registration Statements:

> Registration Statement on Form F-3 (File Nos. 333-208478 and 333-208478-01) of BP Capital Markets p.l.c. and BP p.l.c.; and Registration Statements on Form S-8 (File Nos. 333-67206, 333-79399, 333-103924, 333-123482, 333-123483, 333-131583, 333-131584, 333-132619, 333-146868, 333-146870, 333-146873, 333-173136, 333-177423, 333-179406, 333-186462, 333-186463, 333-199015, 333-200794, 333-200795, 333-207188 and 333-207189) of BP p.l.c.

/s/ Ernst & Young LLP
London, United Kingdom
4 March 2016

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Group income statement

For the year ended 31 December $ million

	Note	2015	2014	2013
Sales and other operating revenues	5	**222,894**	353,568	379,136
Earnings from joint ventures – after interest and tax	15	**(28)**	570	447
Earnings from associates – after interest and tax	16	**1,839**	2,802	2,742
Interest and other income	6	**611**	843	777
Gains on sale of businesses and fixed assets	4	**666**	895	13,115
Total revenues and other income		**225,982**	358,678	396,217
Purchases	18	**164,790**	281,907	298,351
Production and manufacturing expenses[a]		**37,040**	27,375	27,527
Production and similar taxes	5	**1,036**	2,958	7,047
Depreciation, depletion and amortization	5	**15,219**	15,163	13,510
Impairment and losses on sale of businesses and fixed assets	4	**1,909**	8,965	1,961
Exploration expense	7	**2,353**	3,632	3,441
Distribution and administration expenses		**11,553**	12,266	12,611
Profit (loss) before interest and taxation		**(7,918)**	6,412	31,769
Finance costs[a]	6	**1,347**	1,148	1,068
Net finance expense relating to pensions and other post-retirement benefits	23	**306**	314	480
Profit (loss) before taxation		**(9,571)**	4,950	30,221
Taxation[a]	8	**(3,171)**	947	6,463
Profit (loss) for the year		**(6,400)**	4,003	23,758
Attributable to				
BP shareholders		**(6,482)**	3,780	23,451
Non-controlling interests		**82**	223	307
		(6,400)	4,003	23,758
Earnings per share – cents				
Profit (loss) for the year attributable to BP shareholders				
Basic	10	**(35.39)**	20.55	123.87
Diluted	10	**(35.39)**	20.42	123.12

[a] See Note 2 for information on the impact of the Gulf of Mexico oil spill on these income statement line items.

Group statement of comprehensive income[a]

For the year ended 31 December — $ million

	Note	2015	2014	2013
Profit (loss) for the year		**(6,400)**	4,003	23,758
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**(4,119)**	(6,838)	(1,608)
Exchange gains (losses) on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**23**	51	22
Available-for-sale investments marked to market		**1**	(1)	(172)
Available-for-sale investments reclassified to the income statement		**–**	1	(523)
Cash flow hedges marked to market	29	**(178)**	(155)	(2,000)
Cash flow hedges reclassified to the income statement	29	**249**	(73)	4
Cash flow hedges reclassified to the balance sheet	29	**22**	(11)	17
Share of items relating to equity-accounted entities, net of tax		**(814)**	(2,584)	(24)
Income tax relating to items that may be reclassified	8	**257**	147	147
		(4,559)	(9,463)	(4,137)
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	23	**4,139**	(4,590)	4,764
Share of items relating to equity-accounted entities, net of tax		**(1)**	4	2
Income tax relating to items that will not be reclassified	8	**(1,397)**	1,334	(1,521)
		2,741	(3,252)	3,245
Other comprehensive income		**(1,818)**	(12,715)	(892)
Total comprehensive income		**(8,218)**	(8,712)	22,866
Attributable to				
BP shareholders		**(8,259)**	(8,903)	22,574
Non-controlling interests		**41**	191	292
		(8,218)	(8,712)	22,866

[a] See Note 31 for further information.

Group statement of changes in equity[a]

$ million

	Share capital and capital reserves	Treasury shares	Foreign currency translation reserve	Fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
At 1 January 2015	**43,902**	**(20,719)**	**(3,409)**	**(897)**	**92,564**	**111,441**	**1,201**	**112,642**
Profit (loss) for the year	**–**	**–**	**–**	**–**	**(6,482)**	**(6,482)**	**82**	**(6,400)**
Other comprehensive income	**–**	**–**	**(3,858)**	**74**	**2,007**	**(1,777)**	**(41)**	**(1,818)**
Total comprehensive income	**–**	**–**	**(3,858)**	**74**	**(4,475)**	**(8,259)**	**41**	**(8,218)**
Dividends[b]	**–**	**–**	**–**	**–**	**(6,659)**	**(6,659)**	**(91)**	**(6,750)**
Share-based payments, net of tax	**–**	**755**	**–**	**–**	**(99)**	**656**	**–**	**656**
Share of equity-accounted entities' changes in equity, net of tax	**–**	**–**	**–**	**–**	**40**	**40**	**–**	**40**
Transactions involving non-controlling interests	**–**	**–**	**–**	**–**	**(3)**	**(3)**	**20**	**17**
At 31 December 2015	**43,902**	**(19,964)**	**(7,267)**	**(823)**	**81,368**	**97,216**	**1,171**	**98,387**
At 1 January 2014	43,656	(20,971)	3,525	(695)	103,787	129,302	1,105	130,407
Profit (loss) for the year	–	–	–	–	3,780	3,780	223	4,003
Other comprehensive income	–	–	(6,934)	(202)	(5,547)	(12,683)	(32)	(12,715)
Total comprehensive income	–	–	(6,934)	(202)	(1,767)	(8,903)	191	(8,712)
Dividends[b]	–	–	–	–	(5,850)	(5,850)	(255)	(6,105)
Repurchases of ordinary share capital	–	–	–	–	(3,366)	(3,366)	–	(3,366)
Share-based payments, net of tax	246	252	–	–	(313)	185	–	185
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	73	73	–	73
Transactions involving non-controlling interests	–	–	–	–	–	–	160	160
At 31 December 2014	43,902	(20,719)	(3,409)	(897)	92,564	111,441	1,201	112,642
At 1 January 2013	43,513	(21,054)	5,128	1,775	89,184	118,546	1,206	119,752
Profit (loss) for the year	–	–	–	–	23,451	23,451	307	23,758
Other comprehensive income	–	–	(1,603)	(2,470)	3,196	(877)	(15)	(892)
Total comprehensive income	–	–	(1,603)	(2,470)	26,647	22,574	292	22,866
Dividends[b]	–	–	–	–	(5,441)	(5,441)	(469)	(5,910)
Repurchases of ordinary share capital	–	–	–	–	(6,923)	(6,923)	–	(6,923)
Share-based payments, net of tax	143	83	–	–	247	473	–	473
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	73	73	–	73
Transactions involving non-controlling interests	–	–	–	–	–	–	76	76
At 31 December 2013	43,656	(20,971)	3,525	(695)	103,787	129,302	1,105	130,407

[a] See Note 31 for further information.
[b] See Note 9 for further information.

Group balance sheet

At 31 December

	Note	2015	2014
			$ million
Non-current assets			
Property, plant and equipment	11	**129,758**	130,692
Goodwill	13	**11,627**	11,868
Intangible assets	14	**18,660**	20,907
Investments in joint ventures	15	**8,412**	8,753
Investments in associates	16	**9,422**	10,403
Other investments	17	**1,002**	1,228
Fixed assets		**178,881**	183,851
Loans		**529**	659
Trade and other receivables	19	**2,216**	4,787
Derivative financial instruments	29	**4,409**	4,442
Prepayments		**1,003**	964
Deferred tax assets	8	**1,545**	2,309
Defined benefit pension plan surpluses	23	**2,647**	31
		191,230	197,043
Current assets			
Loans		**272**	333
Inventories	18	**14,142**	18,373
Trade and other receivables	19	**22,323**	31,038
Derivative financial instruments	29	**4,242**	5,165
Prepayments		**1,838**	1,424
Current tax receivable		**599**	837
Other investments	17	**219**	329
Cash and cash equivalents	24	**26,389**	29,763
		70,024	87,262
Assets classified as held for sale	3	**578**	–
		70,602	87,262
Total assets		**261,832**	284,305
Current liabilities			
Trade and other payables	21	**31,949**	40,118
Derivative financial instruments	29	**3,239**	3,689
Accruals		**6,261**	7,102
Finance debt	25	**6,944**	6,877
Current tax payable		**1,080**	2,011
Provisions	22	**5,154**	3,818
		54,627	63,615
Liabilities directly associated with assets classified as held for sale	3	**97**	–
		54,724	63,615
Non-current liabilities			
Other payables	21	**2,910**	3,587
Derivative financial instruments	29	**4,283**	3,199
Accruals		**890**	861
Finance debt	25	**46,224**	45,977
Deferred tax liabilities	8	**9,599**	13,893
Provisions	22	**35,960**	29,080
Defined benefit pension plan and other post-retirement benefit plan deficits	23	**8,855**	11,451
		108,721	108,048
Total liabilities		**163,445**	171,663
Net assets		**98,387**	112,642
Equity			
BP shareholders' equity	31	**97,216**	111,441
Non-controlling interests	31	**1,171**	1,201
Total equity	31	**98,387**	112,642

C-H Svanberg Chairman
R W Dudley Group Chief Executive
4 March 2016

Group cash flow statement

For the year ended 31 December

	Note	2015	2014	2013
				$ million
Operating activities				
Profit (loss) before taxation		**(9,571)**	4,950	30,221
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities				
Exploration expenditure written off	7	**1,829**	3,029	2,710
Depreciation, depletion and amortization	5	**15,219**	15,163	13,510
Impairment and (gain) loss on sale of businesses and fixed assets	4	**1,243**	8,070	(11,154)
Earnings from joint ventures and associates		**(1,811)**	(3,372)	(3,189)
Dividends received from joint ventures and associates		**1,614**	1,911	1,391
Interest receivable		**(247)**	(276)	(314)
Interest received		**176**	81	173
Finance costs	6	**1,347**	1,148	1,068
Interest paid		**(1,080)**	(937)	(1,084)
Net finance expense relating to pensions and other post-retirement benefits	23	**306**	314	480
Share-based payments		**321**	379	297
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	23	**(592)**	(963)	(920)
Net charge for provisions, less payments		**11,792**	1,119	1,061
(Increase) decrease in inventories		**3,375**	10,169	(1,193)
(Increase) decrease in other current and non-current assets		**6,796**	3,566	(2,718)
Increase (decrease) in other current and non-current liabilities		**(9,328)**	(6,810)	(2,932)
Income taxes paid		**(2,256)**	(4,787)	(6,307)
Net cash provided by operating activities		**19,133**	32,754	21,100
Investing activities				
Capital expenditure		**(18,648)**	(22,546)	(24,520)
Acquisitions, net of cash acquired		**23**	(131)	(67)
Investment in joint ventures		**(265)**	(179)	(451)
Investment in associates		**(1,312)**	(336)	(4,994)
Proceeds from disposals of fixed assets	4	**1,066**	1,820	18,115
Proceeds from disposals of businesses, net of cash disposed	4	**1,726**	1,671	3,884
Proceeds from loan repayments		**110**	127	178
Net cash used in investing activities		**(17,300)**	(19,574)	(7,855)
Financing activities				
Net issue (repurchase) of shares		**–**	(4,589)	(5,358)
Proceeds from long-term financing		**8,173**	12,394	8,814
Repayments of long-term financing		**(6,426)**	(6,282)	(5,959)
Net increase (decrease) in short-term debt		**473**	(693)	(2,019)
Net increase (decrease) in non-controlling interests		**(5)**	9	32
Dividends paid				
BP shareholders	9	**(6,659)**	(5,850)	(5,441)
Non-controlling interests		**(91)**	(255)	(469)
Net cash used in financing activities		**(4,535)**	(5,266)	(10,400)
Currency translation differences relating to cash and cash equivalents		**(672)**	(671)	40
Increase (decrease) in cash and cash equivalents		**(3,374)**	7,243	2,885
Cash and cash equivalents at beginning of year		**29,763**	22,520	19,635
Cash and cash equivalents at end of year		**26,389**	29,763	22,520

Notes on financial statements

1. Significant accounting policies, judgements, estimates and assumptions

Authorization of financial statements and statement of compliance with International Financial Reporting Standards

The consolidated financial statements of the BP group for the year ended 31 December 2015 were approved and signed by the group chief executive and chairman on 4 March 2016 having been duly authorized to do so by the board of directors. BP p.l.c. is a public limited company incorporated and domiciled in England and Wales. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), IFRS as adopted by the European Union (EU) and in accordance with the provisions of the UK Companies Act 2006. IFRS as adopted by the EU differs in certain respects from IFRS as issued by the IASB. The differences have no impact on the group's consolidated financial statements for the years presented. The significant accounting policies and accounting judgements, estimates and assumptions of the group are set out below.

Basis of preparation

The consolidated financial statements have been prepared on a going concern basis and in accordance with IFRS and IFRS Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2015. The accounting policies that follow have been consistently applied to all years presented.

The consolidated financial statements are presented in US dollars and all values are rounded to the nearest million dollars ($ million), except where otherwise indicated.

Significant accounting policies: use of judgements, estimates and assumptions

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for BP management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. Actual outcomes could differ from the estimates and assumptions used. The accounting judgements and estimates that could have a significant impact on the results of the group are set out in boxed text below, and should be read in conjunction with the information provided in the Notes on financial statements. The areas requiring the most significant judgement and estimation in the preparation of the consolidated financial statements are: accounting for interests in other entities; oil and natural gas accounting, including the estimation of reserves; the recoverability of asset carrying values; derivative financial instruments, including the application of hedge accounting; provisions and contingencies, in particular provisions and contingencies related to the Gulf of Mexico oil spill; pensions and other post-retirement benefits; and taxation.

Basis of consolidation

The group financial statements consolidate the financial statements of BP p.l.c. and its subsidiaries drawn up to 31 December each year. Subsidiaries are consolidated from the date of their acquisition, being the date on which the group obtains control, and continue to be consolidated until the date that such control ceases. The financial statements of subsidiaries are prepared for the same reporting year as the parent company, using consistent accounting policies. Intra-group balances and transactions, including unrealized profits arising from intra-group transactions, have been eliminated. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred. Non-controlling interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to BP shareholders.

Interests in other entities

Goodwill

Goodwill is initially measured as the excess of the aggregate of the consideration transferred, the amount recognized for any non-controlling interest and the acquisition-date fair values of any previously held interest in the acquiree over the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date. At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units, or groups of cash-generating units, expected to benefit from the combination's synergies. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount under UK generally accepted accounting practice, less subsequent impairments.

Goodwill may also arise upon investments in joint ventures and associates, being the surplus of the cost of investment over the group's share of the net fair value of the identifiable assets and liabilities. Such goodwill is recorded within the corresponding investment in joint ventures and associates.

Interests in joint arrangements

The results, assets and liabilities of joint ventures are incorporated in these financial statements using the equity method of accounting as described below.

Certain of the group's activities, particularly in the Upstream segment, are conducted through joint operations. BP recognizes, on a line-by-line basis in the consolidated financial statements, its share of the assets, liabilities and expenses of these joint operations incurred jointly with the other partners, along with the group's income from the sale of its share of the output and any liabilities and expenses that the group has incurred in relation to the joint operation.

Interests in associates

The results, assets and liabilities of associates are incorporated in these financial statements using the equity method of accounting as described below.

Significant estimate or judgement: accounting for interests in other entities

Judgement is required in assessing the level of control obtained in a transaction to acquire an interest in another entity; depending upon the facts and circumstances in each case, BP may obtain control, joint control or significant influence over the entity or arrangement. Transactions which give BP control of a business are business combinations. If BP obtains joint control of an arrangement, judgement is also required to assess whether the arrangement is a joint operation or a joint venture. If BP has neither control nor joint control, it may be in a position to exercise significant influence over the entity, which is then accounted for as an associate.

Since 21 March 2013, BP has owned 19.75% of the voting shares of OJSC Oil Company Rosneft (Rosneft), a Russian oil and gas company. The Russian federal government, through its investment company OJSC Rosneftegaz, owned 69.5% of the voting shares of Rosneft at 31 December 2015. BP uses the equity method of accounting for its investment in Rosneft because under IFRS it is considered to have significant influence. Significant influence is defined as the power to participate in the financial and operating policy decisions of the investee but is not control or joint control. IFRS identifies several indicators that may provide evidence of significant influence, including representation on the board of directors of the investee and participation in policy-making processes. BP's group chief executive, Bob Dudley, has been a member of the board of directors of

Rosneft since 2013 and he is a member of the Rosneft board's Strategic Planning Committee. During 2015, a second BP-nominated director, Guillermo Quintero, was elected to the Rosneft board. BP also holds the voting rights at general meetings of shareholders conferred by its 19.75% stake in Rosneft. In management's judgement, the group has significant influence over Rosneft, as defined by the relevant accounting standard, and the investment is, therefore, accounted for as an associate. BP's share of Rosneft's oil and natural gas reserves is included in the estimated net proved reserves of equity-accounted entities.

The equity method of accounting

Under the equity method, the investment is carried on the balance sheet at cost plus post-acquisition changes in the group's share of net assets of the entity, less distributions received and less any impairment in value of the investment. Loans advanced to equity-accounted entities that have the characteristics of equity financing are also included in the investment on the group balance sheet. The group income statement reflects the group's share of the results after tax of the equity-accounted entity, adjusted to account for depreciation, amortization and any impairment of the equity-accounted entity's assets based on their fair values at the date of acquisition. The group statement of comprehensive income includes the group's share of the equity-accounted entity's other comprehensive income. The group's share of amounts recognized directly in equity by an equity-accounted entity is recognized directly in the group's statement of changes in equity.

Financial statements of equity-accounted entities are prepared for the same reporting year as the group. Where material differences arise, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group.

Unrealized gains on transactions between the group and its equity-accounted entities are eliminated to the extent of the group's interest in the equity-accounted entity.

The group assesses investments in equity-accounted entities for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If any such indication of impairment exists, the carrying amount of the investment is compared with its recoverable amount, being the higher of its fair value less costs of disposal and value in use. If the carrying amount exceeds the recoverable amount, the investment is written down to its recoverable amount.

The group ceases to use the equity method of accounting from the date on which it no longer has joint control over the joint venture or significant influence over the associate, or when the interest becomes classified as an asset held for sale.

Segmental reporting

The group's operating segments are established on the basis of those components of the group that are evaluated regularly by the group chief executive, BP's chief operating decision maker, in deciding how to allocate resources and in assessing performance.

The accounting policies of the operating segments are the same as the group's accounting policies described in this note, except that IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker. For BP, this measure of profit or loss is replacement cost profit before interest and tax which reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses from profit. Replacement cost profit for the group is not a recognized measure under IFRS. For further information see Note 5.

Foreign currency translation

In individual subsidiaries, joint ventures and associates, transactions in foreign currencies are initially recorded in the functional currency of those entities at the spot exchange rate on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the spot exchange rate on the balance sheet date. Any resulting exchange differences are included in the income statement, unless hedge accounting is applied. Non-monetary assets and liabilities, other than those measured at fair value, are not retranslated subsequent to initial recognition.

In the consolidated financial statements, the assets and liabilities of non-US dollar functional currency subsidiaries, joint ventures, associates, and related goodwill, are translated into US dollars at the spot exchange rate on the balance sheet date. The results and cash flows of non-US dollar functional currency subsidiaries, joint ventures and associates are translated into US dollars using average rates of exchange. In the consolidated financial statements, exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency subsidiaries, joint ventures and associates are translated into US dollars are taken to a separate component of equity and reported in the statement of comprehensive income. Exchange gains and losses arising on long-term intra-group foreign currency borrowings used to finance the group's non-US dollar investments are also taken to other comprehensive income. On disposal or partial disposal of a non-US dollar functional currency subsidiary, joint venture or associate, the related cumulative exchange gains and losses recognized in equity are reclassified to the income statement.

Non-current assets held for sale

Non-current assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell.

Non-current assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition subject only to terms that are usual and customary for sales of such assets. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification as held for sale, and actions required to complete the plan of sale should indicate that it is unlikely that significant changes to the plan will be made or that the plan will be withdrawn.

Property, plant and equipment and intangible assets are not depreciated or amortized once classified as held for sale.

Intangible assets

Intangible assets, other than goodwill, include expenditure on the exploration for and evaluation of oil and natural gas resources, computer software, patents, licences and trademarks and are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses.

Intangible assets acquired separately from a business are carried initially at cost. An intangible asset acquired as part of a business combination is measured at fair value at the date of acquisition and is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights.

Intangible assets with a finite life, other than capitalized exploration and appraisal costs as described below, are amortized on a straight-line basis over their expected useful lives. For patents, licences and trademarks, expected useful life is the shorter of the duration of the legal agreement and economic useful life, and can range from three to 15 years. Computer software costs generally have a useful life of three to five years.

1. Significant accounting policies, judgements, estimates and assumptions – continued

The expected useful lives of assets are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

Oil and natural gas exploration, appraisal and development expenditure

Oil and natural gas exploration, appraisal and development expenditure is accounted for using the principles of the successful efforts method of accounting as described below.

Licence and property acquisition costs

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations, and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to property, plant and equipment.

Exploration and appraisal expenditure

Geological and geophysical exploration costs are recognized as an expense as incurred. Costs directly associated with an exploration well are initially capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs and payments made to contractors. If potentially commercial quantities of hydrocarbons are not found, the exploration well costs are written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an asset. If it is determined that development will not occur then the costs are expensed.

Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalized as an intangible asset. When proved reserves of oil and natural gas are determined and development is approved by management, the relevant expenditure is transferred to property, plant and equipment.

Development expenditure

Expenditure on the construction, installation and completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including service and unsuccessful development or delineation wells, is capitalized within property, plant and equipment and is depreciated from the commencement of production as described below in the accounting policy for property, plant and equipment.

Significant estimate or judgement: oil and natural gas accounting

The determination of whether potentially economic oil and natural gas reserves have been discovered by an exploration well is usually made within one year of well completion, but can take longer, depending on the complexity of the geological structure. Exploration wells that discover potentially economic quantities of oil and natural gas and are in areas where major capital expenditure (e.g. an offshore platform or a pipeline) would be required before production could begin, and where the economic viability of that major capital expenditure depends on the successful completion of further exploration work in the area, remain capitalized on the balance sheet as long as additional exploration or appraisal work is under way or firmly planned.

It is not unusual to have exploration wells and exploratory-type stratigraphic test wells remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and natural gas field is performed or while the optimum development plans and timing are established. All such carried costs are subject to regular technical, commercial and management review on at least an annual basis to confirm the continued intent to develop, or otherwise extract value from, the discovery. Where this is no longer the case, the costs are immediately expensed.

One of the facts and circumstances which indicate that an entity should test such assets for impairment is that the period for which the entity has a right to explore in the specific area has expired or will expire in the near future, and is not expected to be renewed. BP has leases in the Gulf of Mexico making up a prospect, some with terms which were scheduled to expire at the end of 2013 and some with terms which were scheduled to expire at the end of 2014. A significant proportion of our capitalized exploration and appraisal costs in the Gulf of Mexico relate to this prospect. This prospect requires the development of subsea technology to ensure that the hydrocarbons can be extracted safely. BP is in negotiation with the US Bureau of Safety and Environmental Enforcement in relation to seeking extension of these leases so that the discovered hydrocarbons can be developed. BP remains committed to developing this prospect and expects that the leases will be renewed and, therefore, continues to carry the capitalized costs on its balance sheet.

Property, plant and equipment

Property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into the location and condition necessary for it to be capable of operating in the manner intended by management, the initial estimate of any decommissioning obligation, if any, and, for assets that necessarily take a substantial period of time to get ready for their intended use, finance costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included within property, plant and equipment.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the group, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. Inspection costs associated with major maintenance programmes are capitalized and amortized over the period to the next inspection. Overhaul costs for major maintenance programmes, and all other maintenance costs are expensed as incurred.

Oil and natural gas properties, including related pipelines, are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, common facilities and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the depreciation of common facilities takes into account expenditures incurred to date, together with estimated future capital expenditure expected to be incurred relating to as yet undeveloped reserves expected to be processed through these common facilities.

1. Significant accounting policies, judgements, estimates and assumptions – continued

Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life. The typical useful lives of the group's other property, plant and equipment are as follows:

Land improvements	15 to 25 years
Buildings	20 to 50 years
Refineries	20 to 30 years
Petrochemicals plants	20 to 30 years
Pipelines	10 to 50 years
Service stations	15 years
Office equipment	3 to 7 years
Fixtures and fittings	5 to 15 years

The expected useful lives of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period in which the item is derecognized.

Significant estimate or judgement: estimation of oil and natural gas reserves

The determination of the group's estimated oil and natural gas reserves requires significant judgements and estimates to be applied and these are regularly reviewed and updated. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity, drilling of new wells, and commodity prices all impact on the determination of the group's estimates of its oil and natural gas reserves. BP bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements.

The estimation of oil and natural gas reserves and BP's process to manage reserves bookings is described in Supplementary information on oil and natural gas on page 169, which is unaudited. Details on BP's proved reserves and production compliance and governance processes are provided on page 228.

Estimates of oil and natural gas reserves are used to calculate depreciation, depletion and amortization charges for the group's oil and gas properties. The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining carrying value of the asset over the expected future production. Oil and natural gas reserves also have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements. If proved reserves estimates are revised downwards, earnings could be affected by changes in depreciation expense or an immediate write-down of the property's carrying value.

The 2015 movements in proved reserves are reflected in the tables showing movements in oil and natural gas reserves by region in Supplementary information on oil and natural gas (unaudited) on page 169. Information on the carrying amounts of the group's oil and natural gas properties, together with the amounts recognized in the income statement as depreciation, depletion and amortization is contained in Note 11 and Note 5 respectively.

Impairment of property, plant and equipment, intangible assets, and goodwill

The group assesses assets or groups of assets, called cash-generating units (CGUs), for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or CGU may not be recoverable; for example, changes in the group's business plans, changes in the group's assumptions about commodity prices, low plant utilization, evidence of physical damage or, for oil and gas assets, significant downward revisions of estimated reserves or increases in estimated future development expenditure or decommissioning costs. If any such indication of impairment exists, the group makes an estimate of the asset's or CGU's recoverable amount. Individual assets are grouped into CGUs for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

The business segment plans, which are approved on an annual basis by senior management, are the primary source of information for the determination of value in use. They contain forecasts for oil and natural gas production, refinery throughputs, sales volumes for various types of refined products (e.g. gasoline and lubricants), revenues, costs and capital expenditure. As an initial step in the preparation of these plans, various assumptions regarding market conditions, such as oil prices, natural gas prices, refining margins, refined product margins and cost inflation rates are set by senior management. These assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

Fair value less costs of disposal is the price that would be received to sell the asset in an orderly transaction between market participants and does not reflect the effects of factors that may be specific to the group and not applicable to entities in general.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such an indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to the lower of its recoverable amount and the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Impairment reversals are recognized in profit or loss. After a reversal, the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the recoverable amount of the group of cash-generating units to which the goodwill relates should be assessed. In assessing whether goodwill has been impaired, the carrying amount of the group of CGUs to which goodwill has been allocated is compared with its recoverable amount. Where the recoverable amount of the group of CGUs is less than the carrying amount (including goodwill), an impairment loss is recognized. An impairment loss recognized for goodwill is not reversed in a subsequent period.

1. Significant accounting policies, judgements, estimates and assumptions – continued

Significant estimate or judgement: recoverability of asset carrying values

Determination as to whether, and by how much, an asset, CGU, or group of CGUs containing goodwill is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas and refined products.

For oil and natural gas properties, the expected future cash flows are estimated using management's best estimate of future oil and natural gas prices and production and reserves volumes. Judgement is also required when determining the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment testing purposes.

The estimated future level of production in all impairment tests is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes and other factors.

Fair value less costs of disposal may be determined based on similar recent market transaction data or, where recent market transactions for the asset are not available for reference, using discounted cash flow techniques. Where discounted cash flow analyses are used to calculate fair value less costs of disposal, accounting judgements are made about the assumptions market participants would use when pricing the asset, CGU or group of CGUs containing goodwill and the test is performed on a post-tax basis. The post-tax discount rate used is based upon the cost of funding the group derived from an established model. Adjustments are made, where applicable, to take into account any specific risks relating to the country where the cash-generating unit is located. In 2015 the discount rate used to determine recoverable amounts based on fair value less costs of disposal was 7% (2014 8%), with a 2% premium added in higher-risk countries.

When estimating the fair value of our Upstream assets, assumptions reflect all reserves that a market participant would consider when valuing the asset, which are usually broader in scope than the reserves used in a value-in-use test. Discounted cash flow analyses used to calculate fair value less costs of disposal use market prices for the first five years and long-term price assumptions that are consistent with the assumptions used by the group for investment appraisal purposes thereafter. The long-term price assumptions used in such tests are $90 per barrel for Brent in 2021 (2014 $97 per barrel in 2020) and $5.60/mmBtu for Henry Hub in 2021 (2014 $6.00/mmBtu in 2020), both inflated at a rate of 2% per annum for the remaining life of the asset (2014 2.5%). These long-term assumptions are derived from the $80 per barrel real oil price and $5/mmBtu real Henry Hub assumptions used for investment appraisal. In the current price environment, the market prices used for the first five years of both value-in-use and fair value less costs of disposal impairment tests are particularly volatile. Market prices used for the first five years of both value-in-use and fair value less costs of disposal impairment tests performed at the year end are shown in the table below:

Price assumptions for the first five years					**as at 31 December 2015**
	2016	**2017**	**2018**	**2019**	**2020**
Brent oil price ($/bbl)	**40**	**47**	**52**	**54**	**56**
Henry Hub natural gas price ($/mmBtu)	**2.38**	**2.76**	**2.90**	**3.03**	**3.18**
					as at 31 December 2014
	2015	2016	2017	2018	2019
Brent oil price ($/bbl)	61	69	73	76	77
Henry Hub natural gas price ($/mmBtu)	3.11	3.53	3.82	4.00	4.15

For value-in-use calculations, future cash flows are adjusted for risks specific to the cash-generating unit and are discounted using a pre-tax discount rate. The pre-tax discount rate is derived from the cost of funding the group calculated using an established model, and is adjusted, where applicable, to take into account any specific risks relating to the country where the cash-generating unit is located. In 2015 the discount rate used to determine recoverable amounts based on value in use was 11% (2014 12%), with a 2% premium added in higher-risk countries. The discount rates applied in assessments of impairment are reassessed each year. Reserves assumptions for value-in-use tests are restricted to proved and probable reserves.

For value-in-use calculations relating to Upstream assets, prices for oil and natural gas used for future cash flow calculations are based on market prices for the first five years (consistent with those shown in the table above) and the group's flat nominal long-term price assumptions thereafter. As at 31 December 2015, the group's long-term flat nominal price assumptions were $90 per barrel for Brent and $6.50/mmBtu for Henry Hub (2014 $90 per barrel and $6.50/mmBtu). These long-term price assumptions are subject to periodic review.

Irrespective of whether there is any indication of impairment, BP is required to test annually for impairment of goodwill acquired in a business combination. The group carries goodwill of approximately $11.6 billion on its balance sheet (2014 $11.9 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. In testing goodwill for impairment, the group uses the approach described above to determine recoverable amount. If there are low oil or natural gas prices, refining margins or marketing margins for an extended period, the group may need to recognize goodwill impairment charges.

The recoverability of intangible exploration and appraisal expenditure is covered under Oil and natural gas exploration, appraisal and development expenditure above.

Details of impairment charges and reversals recognized in the income statement are provided in Note 4 and details on the carrying amounts of assets are shown in Note 11, Note 13 and Note 14.

Inventories

Inventories, other than inventories held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses. Net realizable value is determined by reference to prices existing at the balance sheet date, adjusted where the sale of inventories after the reporting period gives evidence about their net realizable value at the end of the period.

Inventories held for trading purposes are stated at fair value less costs to sell and any changes in fair value are recognized in the income statement.

Supplies are valued at the lower of cost on a weighted average basis and net realizable value.

Leases

Finance leases are capitalized at the commencement of the lease term at the fair value of the leased item or, if lower, at the present value of the minimum lease payments. Finance charges are allocated to each period so as to achieve a constant rate of interest on the remaining balance of the liability and are charged directly against income. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Operating lease payments are recognized as an expense on a straight-line basis over the lease term.

Financial assets

Financial assets are recognized initially at fair value, normally being the transaction price plus, in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs. The subsequent measurement of financial assets depends on their classification, as follows:

Loans and receivables

Loans and receivables are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired, as well as through the amortization process. This category of financial assets includes trade and other receivables. Cash equivalents are short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and have a maturity of three months or less from the date of acquisition.

Financial assets at fair value through profit or loss

Financial assets at fair value through profit or loss are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category.

Derivatives designated as hedging instruments in an effective hedge

These derivatives are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Held-to-maturity financial assets

Held-to-maturity financial assets are measured at amortized cost, using the effective interest method, less any impairment.

Available-for-sale financial assets

Available-for-sale financial assets are measured at fair value, with gains or losses recognized within other comprehensive income, except for impairment losses, and, for available-for-sale debt instruments, foreign exchange gains or losses, interest recognized using the effective interest method, and any changes in fair value arising from revised estimates of future cash flows, which are recognized in profit or loss.

Impairment of loans and receivables

The group assesses at each balance sheet date whether a financial asset or group of financial assets is impaired. If there is objective evidence that an impairment loss on loans and receivables carried at amortized cost has been incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. The carrying amount of the asset is reduced, with the amount of the loss recognized in the income statement.

Significant estimate or judgement: recoverability of trade receivables

Judgements are required in assessing the recoverability of overdue trade receivables and determining whether a provision against those receivables is required. Factors considered include the credit rating of the counterparty, the amount and timing of anticipated future payments and any possible actions that can be taken to mitigate the risk of non-payment. See Note 28 for information on overdue receivables.

Financial liabilities

The measurement of financial liabilities depends on their classification, as follows:

Financial liabilities at fair value through profit or loss

Financial liabilities at fair value through profit or loss are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category.

Derivatives designated as hedging instruments in an effective hedge

These derivatives are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Financial liabilities measured at amortized cost

All other financial liabilities are initially recognized at fair value, net of transaction costs. For interest-bearing loans and borrowings this is the fair value of the proceeds received net of issue costs associated with the borrowing.

After initial recognition, other financial liabilities are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized in interest and other income and finance costs respectively.

This category of financial liabilities includes trade and other payables and finance debt, except finance debt designated in a fair value hedge relationship.

Derivative financial instruments and hedging activities

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices, as well as for trading purposes. These derivative financial instruments are recognized initially at fair value on the date on which a derivative contract is entered into and subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Contracts to buy or sell a non-financial item (for example, oil, oil products, gas or power) that can be settled net in cash, with the exception of contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the group's expected purchase, sale or usage requirements, are accounted for as financial instruments. Gains or losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

If, at inception of a contract, the valuation cannot be supported by observable market data, any gain or loss determined by the valuation methodology is not recognized in the income statement but is deferred on the balance sheet and is commonly known as 'day-one gain or loss'. This deferred gain or loss is recognized in the income statement over the life of the contract until substantially all the remaining contract term can be valued using observable market data at which point any remaining deferred gain or loss is recognized in the income statement. Changes in valuation subsequent to the initial valuation are recognized immediately through the income statement.

For the purpose of hedge accounting, hedges are classified as:

- fair value hedges when hedging exposure to changes in the fair value of a recognized asset or liability
- cash flow hedges when hedging exposure to variability in cash flows that is attributable to either a particular risk associated with a recognized asset or liability or a highly probable forecast transaction.

Hedge relationships are formally designated and documented at inception, together with the risk management objective and strategy for undertaking the hedge. The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, and how the entity will assess the hedging instrument effectiveness in offsetting the exposure to changes in the hedged item's fair value or cash flows attributable to the hedged risk. Such hedges are expected at inception to be highly effective in achieving offsetting changes in fair value or cash flows. Hedges meeting the criteria for hedge accounting are accounted for as follows:

Fair value hedges

The change in fair value of a hedging derivative is recognized in profit or loss. The change in the fair value of the hedged item attributable to the risk being hedged is recorded as part of the carrying value of the hedged item and is also recognized in profit or loss. The group applies fair value hedge accounting when hedging interest rate risk and certain currency risks on fixed rate borrowings.

If the criteria for hedge accounting are no longer met, or if the group revokes the designation, the accumulated adjustment to the carrying amount of a hedged item at such time is then amortized to profit or loss over the remaining period to maturity.

Cash flow hedges

The effective portion of the gain or loss on a cash flow hedging instrument is recognized within other comprehensive income, while the ineffective portion is recognized in profit or loss. Amounts taken to other comprehensive income are reclassified to the income statement when the hedged transaction affects profit or loss.

Where the hedged item is a non-financial asset or liability, such as a forecast foreign currency transaction for the purchase of property, plant and equipment, the amounts recognized within other comprehensive income are reclassified to the initial carrying amount of the non-financial asset or liability. Where the hedged item is an equity investment, the amounts recognized in other comprehensive income remain in the separate component of equity until the hedged cash flows affect profit or loss. Where the hedged item is recognized directly in profit or loss, the amounts recognized in other comprehensive income are reclassified to production and manufacturing expenses, except for cash flow hedges of variable interest rate risk which are reclassified to finance costs.

If the hedging instrument expires or is sold, terminated or exercised without replacement or rollover, or if its designation as a hedge is revoked, amounts previously recognized within other comprehensive income remain in equity until the forecast transaction occurs and are reclassified to the income statement or to the initial carrying amount of a non-financial asset or liability as above.

Significant estimate or judgement: application of hedge accounting

The decision as to whether to apply hedge accounting within subsidiaries, and by equity-accounted entities, can have a significant impact on the group's financial statements. Cash flow and fair value hedge accounting is applied to certain finance debt-related instruments in the normal course of business and cash flow hedge accounting is applied to certain highly probable foreign currency transactions as part of the management of currency risk. See Note 16, Note 28 and Note 29 for further information.

Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The group categorizes assets and liabilities measured at fair value into one of three levels depending on the ability to observe inputs employed in their measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are inputs that are observable, either directly or indirectly, other than quoted prices included within level 1 for the asset or liability. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or BP's assumptions about pricing by market participants.

Significant estimate or judgement: valuation of derivatives

In some cases the fair values of derivatives are estimated using internal models due to the absence of quoted prices or other observable, market-corroborated data. This applies to the group's longer-term derivative contracts. The majority of these contracts are valued using models with inputs that include price curves for each of the different products that are built up from available active market pricing data and modelled using the maximum available external pricing information. Additionally, where limited data exists for certain products, prices are determined using historic and long-term pricing relationships. Price volatility is also an input for options models.

Changes in the key assumptions could have a material impact on the fair value gains and losses on derivatives recognized in the income statement. For more information see Note 29.

Offsetting of financial assets and liabilities

Financial assets and liabilities are presented gross in the balance sheet unless both of the following criteria are met: the group currently has a legally enforceable right to set off the recognized amounts; and the group intends to either settle on a net basis or realize the asset and settle the liability simultaneously. A right of set off is the group's legal right to settle an amount payable to a creditor by applying against it an amount receivable from the same counterparty. The relevant legal jurisdiction and laws applicable to the relationships between the parties are considered when assessing whether a current legally enforceable right to set off exists.

Provisions, contingencies and reimbursement assets

Provisions are recognized when the group has a present legal or constructive obligation as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where appropriate, the future cash flow estimates are adjusted to reflect risks specific to the liability.

If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax risk-free rate that reflects current market assessments of the time value of money. Where discounting is used, the increase in the provision due to the passage of time is recognized within finance costs. A provision is discounted using either a nominal discount rate of 2.75% (2014 2.75%) or a real discount rate of 0.75% (2014 0.75%), as appropriate. Provisions are split between amounts expected to be settled within 12 months of the balance sheet date (current) and amounts expected to be settled later (non-current).

1. Significant accounting policies, judgements, estimates and assumptions – continued

Contingent liabilities are possible obligations whose existence will only be confirmed by future events not wholly within the control of the group, or present obligations where it is not probable that an outflow of resources will be required or the amount of the obligation cannot be measured with sufficient reliability. Contingent liabilities are not recognized in the financial statements but are disclosed unless the possibility of an outflow of economic resources is considered remote.

Where the group makes contributions into a separately administered fund for restoration, environmental or other obligations, which it does not control, and the group's right to the assets in the fund is restricted, the obligation to contribute to the fund is recognized as a liability where it is probable that such additional contributions will be made. The group recognizes a reimbursement asset separately, being the lower of the amount of the associated restoration, environmental or other provision and the group's share of the fair value of the net assets of the fund available to contributors.

Significant estimate or judgement: provision relating to the Gulf of Mexico oil spill

Detailed information on the Gulf of Mexico oil spill, including the financial impacts, is provided in Note 2.

During 2015, BP signed agreements in principle, which were subject to execution of definitive agreements, to settle all federal and state claims and claims made by more than 400 local government entities. Further detail is provided in Note 2. Certain agreements are subject to approval by the court of a Consent Decree. A provision for amounts payable under these agreements has, therefore, been recognized. The agreements significantly reduce the uncertainties faced by BP following the Gulf of Mexico oil spill in 2010. However, there continues to be uncertainty regarding the outcome or resolution of current or future litigation and the extent and timing of costs relating to the incident not covered by these agreements.

The provision recognized is the reliable estimate of expenditures required to settle certain present obligations at the end of the reporting period. There are future expenditures, however, for which it is not possible to measure the obligation reliably. These are not provided for, are disclosed as contingent liabilities, and are described in Note 2. Contingent liabilities are disclosed in relation to business economic loss (BEL) claims under the Plaintiffs' Steering Committee (PSC) settlement, securities-related litigation, other litigation, including claims from parties excluded from or who opted out of the PSC settlement, and under the settlement agreements with Anadarko and MOEX and other agreements.

Management believes that no reliable estimate can currently be made of any BEL claims not yet processed or processed but not yet paid, except where an eligibility notice has been issued and is not subject to appeal by BP within the claims facility. The submission deadline for BEL claims passed on 8 June 2015; no further claims can be submitted. A significant number of BEL claims have been received but have not yet been processed and it is not possible to quantify the total value of the claims. A revised policy for the matching of revenue and expenses for BEL claims was introduced in May 2014 and, of the claims assessable under the new policy, the majority have not yet been determined at this time. For this and other reasons set out in Note 2, we are unable to reliably estimate future trends of the number and proportion of claims that will be determined to be eligible, nor can we reliably estimate the value of such claims. A provision for such BEL claims will be established when these uncertainties are sufficiently reduced and a reliable estimate can be made of the liability.

Decommissioning

Liabilities for decommissioning costs are recognized when the group has an obligation to plug and abandon a well, dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reliable estimate of that liability can be made. Where an obligation exists for a new facility or item of plant, such as oil and natural gas production or transportation facilities, this liability will be recognized on construction or installation. Similarly, where an obligation exists for a well, this liability is recognized when it is drilled. An obligation for decommissioning may also crystallize during the period of operation of a well, facility or item of plant through a change in legislation or through a decision to terminate operations; an obligation may also arise in cases where an asset has been sold but the subsequent owner is no longer able to fulfil its decommissioning obligations, for example due to bankruptcy. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. The provision for the costs of decommissioning wells, production facilities and pipelines at the end of their economic lives is estimated using existing technology, at current prices or future assumptions, depending on the expected timing of the activity, and discounted using the real discount rate. The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately 17 years.

An amount equivalent to the decommissioning provision is recognized as part of the corresponding intangible asset (in the case of an exploration or appraisal well) or property, plant and equipment. The decommissioning portion of the property, plant and equipment is subsequently depreciated at the same rate as the rest of the asset. Other than the unwinding of discount on the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding asset.

Environmental expenditures and liabilities

Environmental expenditures that are required in order for the group to obtain future economic benefits from its assets are capitalized as part of those assets. Expenditures that relate to an existing condition caused by past operations that do not contribute to future earnings are expensed.

Liabilities for environmental costs are recognized when a clean-up is probable and the associated costs can be reliably estimated. Generally, the timing of recognition of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The amount recognized is the best estimate of the expenditure required to settle the obligation. Provisions for environmental liabilities have been estimated using existing technology, at current prices and discounted using a real discount rate. The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately five years.

Significant estimate or judgement: provisions

The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest decommissioning obligations facing BP relate to the plugging and abandonment of wells and the removal and disposal of oil and natural gas platforms and pipelines around the world. Most of these decommissioning events are many years in the future and the precise requirements that will have to be met when the removal event occurs are uncertain. Decommissioning technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. BP believes that the impact of any reasonably foreseeable change to these provisions on the group's results of operations, financial position or liquidity will not be material. If oil and natural gas production facilities and pipelines are sold to third parties and the subsequent owner is unable to meet their decommissioning obligations, judgement must be used to determine whether BP is then responsible for decommissioning, and if so the extent of that responsibility. The timing and amounts of future cash flows are subject to significant uncertainty. Any changes in the expected future costs are reflected in both the provision and the asset.

Decommissioning provisions associated with downstream and petrochemicals facilities are generally not recognized, as the potential obligations cannot be measured, given their indeterminate settlement dates. The group performs periodic reviews of its downstream and petrochemicals long-lived assets for any changes in facts and circumstances that might require the recognition of a decommissioning provision.

The provision for environmental liabilities is estimated based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

Other provisions and liabilities are recognized in the period when it becomes probable that there will be a future outflow of funds resulting from past operations or events and the amount of cash outflow can be reliably estimated. The timing of recognition and quantification of the liability require the application of judgement to existing facts and circumstances, which can be subject to change. Since the cash outflows can take place many years in the future, the carrying amounts of provisions and liabilities are reviewed regularly and adjusted to take account of changing facts and circumstances.

The timing and amount of future expenditures are reviewed annually, together with the interest rate used in discounting the cash flows. The interest rate used to determine the balance sheet obligation at the end of 2015 was a real rate of 0.75% (2014 0.75%), which was based on long-dated US government bonds.

Provisions and contingent liabilities relating to the Gulf of Mexico oil spill are discussed in Note 2. Information about the group's other provisions is provided in Note 22. As further described in Note 32, the group is subject to claims and actions. The facts and circumstances relating to particular cases are evaluated regularly in determining whether a provision relating to a specific litigation should be recognized or revised. Accordingly, significant management judgement relating to provisions and contingent liabilities is required, since the outcome of litigation is difficult to predict.

Employee benefits

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of the group. Deferred bonus arrangements that have a vesting date more than 12 months after the balance sheet date are valued on an actuarial basis using the projected unit credit method and amortized on a straight-line basis over the service period until the award vests. The accounting policies for share-based payments and for pensions and other post-retirement benefits are described below.

Share-based payments

Equity-settled transactions

The cost of equity-settled transactions with employees is measured by reference to the fair value at the date at which equity instruments are granted and is recognized as an expense over the vesting period, which ends on the date on which the employees become fully entitled to the award. A corresponding credit is recognized within equity. Fair value is determined by using an appropriate, widely used, valuation model. In valuing equity-settled transactions, no account is taken of any vesting conditions, other than conditions linked to the price of the shares of the company (market conditions). Non-vesting conditions, such as the condition that employees contribute to a savings-related plan, are taken into account in the grant-date fair value, and failure to meet a non-vesting condition, where this is within the control of the employee is treated as a cancellation and any remaining unrecognized cost is expensed.

Cash-settled transactions

The cost of cash-settled transactions is recognized as an expense over the vesting period, measured by reference to the fair value of the corresponding liability which is recognized on the balance sheet. The liability is remeasured at fair value at each balance sheet date until settlement, with changes in fair value recognized in the income statement.

Pensions and other post-retirement benefits

The cost of providing benefits under the group's defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period to determine current service cost and to the current and prior periods to determine the present value of the defined benefit obligation. Past service costs, resulting from either a plan amendment or a curtailment (a reduction in future obligations as a result of a material reduction in the plan membership), are recognized immediately when the company becomes committed to a change.

Net interest expense relating to pensions and other post-retirement benefits, which is recognized in the income statement, represents the net change in present value of plan obligations and the value of plan assets resulting from the passage of time, and is determined by applying the discount rate to the present value of the benefit obligation at the start of the year, and to the fair value of plan assets at the start of the year, taking into account expected changes in the obligation or plan assets during the year.

Remeasurements of the defined benefit liability and asset, comprising actuarial gains and losses, and the return on plan assets (excluding amounts included in net interest described above) are recognized within other comprehensive income in the period in which they occur and are not subsequently reclassified to profit and loss.

The defined benefit pension plan surplus or deficit recognized in the balance sheet for each plan comprises the difference between the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds) and the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price. Defined benefit pension plan surpluses are only recognized to the extent they are recoverable, typically by way of refund.

Contributions to defined contribution plans are recognized in the income statement in the period in which they become payable.

Significant estimate or judgement: pensions and other post-retirement benefits

Accounting for pensions and other post-retirement benefits involves judgement about uncertain events, including estimated retirement dates, salary levels at retirement, mortality rates, determination of discount rates for measuring plan obligations and net interest expense and assumptions for inflation rates.

These assumptions are based on the environment in each country. The assumptions used may vary from year to year, which would affect future net income and net assets. Any differences between these assumptions and the actual outcome also affect future net income and net assets.

Pension and other post-retirement benefit assumptions are reviewed by management at the end of each year. These assumptions are used to determine the projected benefit obligation at the year end and hence the surpluses and deficits recorded on the group's balance sheet, and pension and other post-retirement benefit expense for the following year. The assumptions used are provided in Note 23.

1. Significant accounting policies, judgements, estimates and assumptions – continued

The discount rate and inflation rate have a significant effect on the amounts reported. A sensitivity analysis of the impact of changes in these assumptions on the benefit expense and obligation is provided in Note 23.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. Mortality assumptions reflect best practice in the countries in which we provide pensions and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. A sensitivity analysis of the impact of changes in the mortality assumptions on the benefit expense and obligation is provided in Note 23.

Income taxes

Income tax expense represents the sum of current tax and deferred tax. Interest and penalties relating to income tax are also included in the income tax expense.

Income tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity, in which case the related tax is recognized in other comprehensive income or directly in equity.

Current tax is based on the taxable profit for the period. Taxable profit differs from net profit as reported in the income statement because it is determined in accordance with the rules established by the applicable taxation authorities. It therefore excludes items of income or expense that are taxable or deductible in other periods as well as items that are never taxable or deductible. The group's liability for current tax is calculated using tax rates and laws that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is provided, using the liability method, on temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes. Deferred tax liabilities are recognized for all taxable temporary differences except:

- where the deferred tax liability arises on the initial recognition of goodwill
- where the deferred tax liability arises on the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither accounting profit nor taxable profit or loss
- in respect of taxable temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, where the group is able to control the timing of the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized except where the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither accounting profit nor taxable profit or loss. In respect of deductible temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilized.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date. Deferred tax assets and liabilities are not discounted.

Deferred tax assets and liabilities are offset only when there is a legally enforceable right to set off current tax assets against current tax liabilities and when the deferred tax assets and liabilities relate to income taxes levied by the same taxation authority on either the same taxable entity or different taxable entities where there is an intention to settle the current tax assets and liabilities on a net basis or to realize the assets and settle the liabilities simultaneously.

Significant estimate or judgement: income taxes

The computation of the group's income tax expense and liability involves the interpretation of applicable tax laws and regulations in many jurisdictions throughout the world. The resolution of tax positions taken by the group, through negotiations with relevant tax authorities or through litigation, can take several years to complete and in some cases it is difficult to predict the ultimate outcome. Therefore, judgement is required to determine provisions for income taxes.

In addition, the group has carry-forward tax losses and tax credits in certain taxing jurisdictions that are available to offset against future taxable profit. However, deferred tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused tax losses or tax credits can be utilized. Management judgement is exercised in assessing whether this is the case.

To the extent that actual outcomes differ from management's estimates, income tax charges or credits, and changes in current and deferred tax assets or liabilities, may arise in future periods. For more information see Note 8.

Judgement is also required when determining whether a particular tax is an income tax or another type of tax (for example a production tax). Accounting for deferred tax is applied to income taxes as described above, but is not applied to other types of taxes; rather such taxes are recognized in the income statement on an appropriate basis.

Customs duties and sales taxes

Customs duties and sales taxes which are passed on to customers are excluded from revenues and expenses. Assets and liabilities are recognized net of the amount of customs duties or sales tax except:

- Customs duties or sales taxes incurred on the purchase of goods and services which are not recoverable from the taxation authority are recognized as part of the cost of acquisition of the asset.
- Receivables and payables are stated with the amount of customs duty or sales tax included.

The net amount of sales tax recoverable from, or payable to, the taxation authority is included within receivables or payables in the balance sheet.

1. Significant accounting policies, judgements, estimates and assumptions – continued

Own equity instruments – Treasury shares

The group's holdings in its own equity instruments are shown as deductions from shareholders' equity at cost. Treasury shares represent BP shares repurchased and available for specific and limited purposes. For accounting purposes, shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans are treated in the same manner as treasury shares and are, therefore, included in the financial statements as treasury shares. Consideration, if any, received for the sale of such shares is also recognized in equity, with any difference between the proceeds from sale and the original cost being taken to the profit and loss account reserve. No gain or loss is recognized in the income statement on the purchase, sale, issue or cancellation of equity shares. Shares repurchased under the share buy-back programme which are immediately cancelled are not shown as treasury shares, but are shown as a deduction from the profit and loss account reserve in the group statement of changes in equity.

Revenue

Revenue arising from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer, which is typically at the point that title passes, and the revenue can be reliably measured.

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods provided in the normal course of business, net of discounts, customs duties and sales taxes.

Physical exchanges are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange. Similarly, where the group acts as agent on behalf of a third party to procure or market energy commodities, any associated fee income is recognized but no purchase or sale is recorded. Additionally, where forward sale and purchase contracts for oil, natural gas or power have been determined to be for trading purposes, the associated sales and purchases are reported net within sales and other operating revenues whether or not physical delivery has occurred.

Generally, revenues from the production of oil and natural gas properties in which the group has an interest with joint operation partners are recognized on the basis of the group's working interest in those properties (the entitlement method). Differences between the production sold and the group's share of production are not significant.

Finance costs

Finance costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets until such time as the assets are substantially ready for their intended use. All other finance costs are recognized in the income statement in the period in which they are incurred.

Impact of new International Financial Reporting Standards

There are no new or amended standards or interpretations adopted during the year that have a significant impact on the financial statements.

Not yet adopted

The following pronouncements from the IASB will become effective for future financial reporting periods and have not yet been adopted by the group.

IFRS 9 'Financial Instruments' will supersede IAS 39 'Financial Instruments: Recognition and Measurement' and is effective for annual periods beginning on or after 1 January 2018. IFRS 9 covers classification and measurement of financial assets and financial liabilities, impairment methodology and hedge accounting.

IFRS 15 'Revenue from Contracts with Customers' provides a single model for accounting for revenue arising from contracts with customers and is effective for annual periods beginning on or after 1 January 2018. IFRS 15 will supersede IAS 18 'Revenue'.

The IASB has issued IFRS 16 'Leases' which provides a new model for lease accounting in which all leases, other than short-term and small-ticket-item leases, will be accounted for by the recognition on the balance sheet of a right-to-use asset and a lease liability, and the subsequent amortization of the right-to-use asset over the lease term. IFRS 16 will be effective for annual periods beginning on or after 1 January 2019 and is expected to have a significant effect on the group's financial statements, significantly increasing the group's recognized assets and liabilities and potentially affecting the presentation and timing of recognition of charges in the income statement. Information on the group's leases currently classified as operating leases, which are not recognized on the balance sheet, is provided in Note 27.

BP does not expect to adopt IFRS 9 or IFRS 15 before 1 January 2018 and has not yet determined its date of adoption for IFRS 16. The group has not yet completed its evaluation of the effect of adoption of these standards. The EU has not yet adopted IFRS 9, IFRS 15 or IFRS 16.

There are no other standards and interpretations in issue but not yet adopted that the directors anticipate will have a material effect on the reported income or net assets of the group.

2. Significant event – Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill in April 2010, BP continues to incur costs and has also recognized liabilities for certain future costs. Liabilities of uncertain timing or amount, for which no provision has been made, have been disclosed as contingent liabilities.

The cumulative pre-tax income statement charge since the incident amounts to $55.5 billion. For more information on the types of expenditure included in the cumulative income statement charge, see *Impact upon the group income statement* below. The cumulative income statement charge does not include amounts for obligations that BP considers are not possible, at this time, to measure reliably. For further information, including developments in relation to business economic loss claims under the Plaintiffs' Steering Committee (PSC) settlement, see *Provisions and contingent liabilities* below.

On 2 July 2015, agreements in principle to settle all federal and state claims and claims made by more than 400 local government entities were signed. These agreements in principle were subject to execution of definitive agreements, including a Consent Decree with the United States and Gulf states with respect to the Clean Water Act penalty and natural resource damages and other claims, a Settlement Agreement with five Gulf states with respect to state claims for economic loss, property damage and other claims, and resolution to BP's satisfaction of the economic loss, property damage and other claims with more than 400 local government entities. The proposed Consent Decree between the United States, the Gulf states and BP was available for public comment until early December 2015 and is subject to final court approval. The Consent Decree and Settlement Agreement with the five Gulf states are conditional upon each other and neither will become effective unless there is final court approval of the Consent Decree. The United States is expected to file a motion with the court to enter the Consent Decree as a final settlement around the end of March, which the court will then consider. During 2015, the Settlement Agreement with the five Gulf states was executed. BP has accepted releases received from the vast majority of local government entities and payments required under those releases were made during 2015. For more information on the proposed Consent Decree and Settlement Agreement see Legal proceedings on page 238.

2. Significant event – Gulf of Mexico oil spill – continued

The agreements described above (the Agreements) significantly reduce the uncertainties faced by BP following the Gulf of Mexico oil spill in 2010. There continues to be uncertainty regarding the outcome or resolution of current or future litigation and the extent and timing of costs relating to the incident not covered by the Agreements. The total amounts that will ultimately be paid by BP in relation to the incident will be dependent on many factors, as discussed under *Provisions and contingent liabilities* below, including in relation to any new information or future developments. These uncertainties could have a material impact on our consolidated financial position, results and cash flows.

The impacts of the Gulf of Mexico oil spill on the income statement, balance sheet and cash flow statement of the group are included within the relevant line items in those statements and are shown in the table below.

			$ million
	2015	2014	2013
Income statement			
Production and manufacturing expenses	**11,709**	781	430
Profit (loss) before interest and taxation	**(11,709)**	(781)	(430)
Finance costs	**247**	38	39
Profit (loss) before taxation	**(11,956)**	(819)	(469)
Less: Taxation	**3,492**	262	73
Profit (loss) for the period	**(8,464)**	(557)	(396)
Balance sheet			
Current assets			
Trade and other receivables	**686**	1,154	
Current liabilities			
Trade and other payables	**(693)**	(655)	
Accruals	**(40)**	–	
Provisions	**(3,076)**	(1,702)	
Net current assets (liabilities)	**(3,123)**	(1,203)	
Non-current assets			
Other receivables	**–**	2,701	
Non-current liabilities			
Other payables	**(2,057)**	(2,412)	
Accruals	**(186)**	(169)	
Provisions	**(13,431)**	(6,903)	
Deferred tax	**5,200**	1,723	
Net non-current assets (liabilities)	**(10,474)**	(5,060)	
Net assets (liabilities)	**(13,597)**	(6,263)	
Cash flow statement			
Profit (loss) before taxation	**(11,956)**	(819)	(469)
Finance costs	**247**	38	39
Net charge for provisions, less payments	**11,296**	939	1,129
(Increase) decrease in other current and non-current assets	**–**	(662)	(1,481)
Increase (decrease) in other current and non-current liabilities	**(732)**	(792)	(618)
Pre-tax cash flows	**(1,145)**	(1,296)	(1,400)

The impact on net cash provided by operating activities, on a post-tax basis, amounted to an outflow of $1,130 million (2014 outflow of $9 million and 2013 outflow of $73 million).

Trust fund

BP established the Deepwater Horizon Oil Spill Trust (the Trust), funded in the amount of $20 billion, to satisfy legitimate individual and business claims, state and local government claims resolved by BP, final judgments and settlements, state and local response costs, and natural resource damages and related costs. Fines and penalties are not covered by the trust fund. The funding of the Trust was completed in 2012. The obligation to fund the $20-billion trust fund, adjusted to take account of the time value of money, was recognized in full in 2010 and charged to the income statement.

BP's rights and obligations in relation to the $20-billion trust fund are accounted for in accordance with IFRIC 5 'Rights to Interests Arising from Decommissioning, Restoration and Environmental Rehabilitation Funds'. An asset has been recognized representing BP's right to receive reimbursement from the trust fund. We use the term 'reimbursement asset' to describe this asset. BP does not actually receive any reimbursements from the trust fund, instead payments are made directly from the trust fund, and BP is released from its corresponding obligation. This is the portion of the estimated future expenditure provided for that will be settled by payments from the trust fund. During 2014, cumulative charges to be paid by the Trust reached $20 billion. Subsequent additional costs, over and above those provided within the $20 billion, are expensed to the income statement as incurred.

At 31 December 2015, $686 million of the provisions and payables are eligible to be paid from the Trust. The reimbursement asset is recorded within Trade and other receivables on the balance sheet, all of which is classified as current, as payment of all amounts covered by the remaining reimbursement asset may be requested during 2016. During 2015, $3,022 million of provisions and $147 million of payables were paid from the Trust.

At 31 December 2015, the remaining cash in the Trust not allocated for specific purposes was $25 million. This unallocated amount was exhausted in January 2016 and BP commenced paying claims and other costs not covered by the specific-purpose cash balances. The total cash remaining in the Trust and associated qualifying settlement funds, amounting to $1.4 billion, includes $0.7 billion in the seafood compensation fund, $0.2 billion held for natural resource damage early restoration projects and $0.5 billion held in relation to certain other specified costs under the PSC settlement.

2. Significant event – Gulf of Mexico oil spill – continued

Other payables

BP reached an agreement with the US government in 2012, which was approved by the court in 2013, to resolve all federal criminal claims arising from the incident. At 31 December 2015, $2,432 million remains in Other payables in relation to this agreement, of which $530 million falls due in 2016. In addition, Other payables at 31 December 2015 includes the remaining $219 million for BP's commitment to fund the Gulf of Mexico Research Initiative, which is a 10-year research programme to study the impact of the incident on the marine and shoreline environment of the Gulf of Mexico.

Provisions and contingent liabilities

Provisions

BP has recorded provisions relating to the Gulf of Mexico oil spill in relation to environmental expenditure (including spill response costs), litigation and claims, and Clean Water Act penalties that can be measured reliably at this time.

Movements in each class of provision during the year and cumulatively since the incident are presented in the tables below.

				$ million
				2015
	Environmental	Litigation and claims	Clean Water Act	Total
At 1 January	1,141	3,954	3,510	8,605
Increase in provision	5,393	5,832	661	11,886
Unwinding of discount	94	50	68	212
Change in discount rate	(149)	(74)	(110)	(333)
Reclassified to other payables	(459)	(125)	–	(584)
Utilization – paid by BP	(23)	(234)	–	(257)
– paid by the trust fund	(78)	(2,944)	–	(3,022)
At 31 December	5,919	6,459	4,129	16,507
Of which – current	227	2,849	–	3,076
– non-current	5,692	3,610	4,129	13,431

				$ million
				Cumulative since the incident
	Environmental	Litigation and claims	Clean Water Act	Total
Net increase in provision	19,992	32,427	4,171	56,590
Unwinding of discount	107	56	68	231
Change in discount rate	(130)	(74)	(110)	(314)
Reclassified to other payables	(459)	(4,408)	–	(4,867)
Utilization – paid by BP	(11,710)	(4,314)	–	(16,024)
– paid by the trust fund	(1,881)	(17,228)	–	(19,109)
At 31 December 2015	5,919	6,459	4,129	16,507

Environmental

The environmental provision at 31 December 2015 includes amounts payable for natural resource damage costs under the proposed Consent Decree. These amounts are payable in instalments over 16 years commencing one year after the court approves the Consent Decree; the majority of the unpaid balance of this natural resource damages settlement accrues interest at a fixed rate. During 2011, BP entered into a framework agreement with natural resource trustees for the United States and five Gulf states, providing for $1 billion to be spent on early restoration projects to address natural resource injuries resulting from the oil spill, to be funded from the $20-billion trust fund. Remaining amounts payable under this framework agreement, that are not yet allocated to specific projects, are also included in environmental provisions.

Litigation and claims

The litigation and claims provision includes amounts that can be estimated reliably for the future cost of settling claims by individuals and businesses for damage to real or personal property, lost profits or impairment of earning capacity and loss of subsistence use of natural resources ('Individual and Business Claims'), and amounts provided under the Agreements in relation to state claims that have not yet been paid. Claims administration costs and legal costs have also been provided for.

Litigation and claims – PSC settlement

The Economic and Property Damages Settlement Agreement (EPD Settlement Agreement) with the PSC provides for a court-supervised settlement programme, the Deepwater Horizon Court Supervised Settlement Program (DHCSSP), which commenced operation on 4 June 2012. A separate claims administrator has been appointed to pay medical claims and to implement other aspects of the Medical Benefits Class Action Settlement. For further information on the PSC settlements, see Legal proceedings on page 239. BP has provided for its best estimate of the cost associated with the PSC settlement agreements with the exception of the cost of business economic loss claims, which are provided for where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility.

Management believes that no reliable estimate can currently be made of any business economic loss claims not yet processed or processed but not yet paid, except where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility.

The submission deadline for business economic loss claims passed on 8 June 2015; no further claims may be submitted. A significant number of business economic loss claims have been received but have not yet been processed and it is not possible to quantify the total value of the claims. A revised policy for the matching of revenue and expenses for business economic loss claims was introduced in May 2014 and, of the claims assessable under the revised policy, the majority have not yet been determined at this time. Uncertainties regarding the proper application of the revised policy to particular claims and categories of claims continue to arise as the claims administrator has applied the revised policy. Only a small proportion of claim determinations have been made under some of the specialized frameworks that have been put in place for particular industries, namely construction, agriculture, professional services and education, and so determinations to date may not be representative of the total population

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of claims. In addition, although some pre-determination data has been provided to BP, detailed data on the majority of pre-determination claims is not available due to a court order to protect claimant confidentiality. Therefore, there is an insufficient level of detail to enable a complete or clear understanding of the composition of the underlying claims population.

There is insufficient data available to build up a track record of claims determinations under the policies and protocols that are now being applied following resolution of the matching and causation issues. We are unable to reliably estimate future trends of the number and proportion of claims that will be determined to be eligible, nor can we reliably estimate the value of such claims. A provision for such business economic loss claims will be established when these uncertainties are sufficiently reduced and a reliable estimate can be made of the liability.

The current estimate for the total cost of those elements of the PSC settlement that BP considers can be reliably estimated, including amounts already paid, is $12.4 billion. Prior to the end of the month following the balance sheet date, the DHCSSP had issued eligibility notices, many of which are disputed by BP, in respect of business economic loss claims of approximately $402 million which have not been provided for. The total cost of the PSC settlement is likely to be significantly higher than the amount recognized to date of $12.4 billion because the current estimate does not reflect business economic loss claims not yet processed, or processed but not yet paid, except where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility.

There continues to be a high level of uncertainty with regards to the amounts that ultimately will be paid in relation to current claims as described above and there is also uncertainty as to the cost of administering the claims process under the DHCSSP and in relation to future legal costs. The timing of payment of provisions related to the PSC settlement is dependent upon ongoing claims facility activity and is therefore also uncertain.

Litigation and claims – Other claims

The provision recognized for litigation and claims includes amounts agreed under the Agreements in relation to state claims. The amount provided in respect of state claims is payable over 18 years from the date the court approves the Consent Decree, of which $1 billion is due following the court approval of the Consent Decree. The vast majority of local government entities who filed claims have issued releases, which were accepted by BP; amounts due under those releases were paid during 2015.

Clean Water Act penalties

A provision has been recognized for penalties under Section 311 of the Clean Water Act, as determined in the Agreements. The amount is payable in instalments over 15 years, commencing one year after the court approves the Consent Decree. The unpaid balance of this penalty accrues interest at a fixed rate.

Provision movements

The total amount recognized as an increase in provisions during the year was $11,886 million. This increase relates primarily to amounts provided for the Agreements, and additional increases in the litigation and claims provision for business economic loss claims, associated claims administration costs and other items. After deducting amounts utilized during the year totalling $3,279 million, comprising payments from the trust fund of $3,022 million and payments made directly by BP of $257 million (2014 $2,071 million, comprising payments from the trust fund of $1,681 million and payments made directly by BP of $390 million), and after adjustments for discounting, the remaining provision as at 31 December 2015 was $16,507 million (2014 $8,605 million).

Contingent liabilities

BP has provided for its best estimate of amounts expected to be paid that can be measured reliably. It is not possible, at this time, to measure reliably other obligations arising from the incident, nor is it practicable to estimate their magnitude or possible timing of payment. Therefore, no amounts have been provided for these obligations as at 31 December 2015.

Business economic loss claims under the PSC settlement

The potential cost of business economic loss claims not yet processed and paid (except where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility) is not provided for and is disclosed as a contingent liability. A significant number of business economic loss claims have been received but have not yet been processed and paid. See *Provisions* above for further information.

Securities-related litigation

Proceedings relating to securities class actions (MDL 2185) pending in federal court in Texas, including a purported class action on behalf of purchasers of American Depositary Shares under US federal securities law, are continuing. A jury trial is scheduled to begin in July 2016 and the timing of any outflow of resources, if any, is dependent on the duration of the court process. No reliable estimate can be made of the amounts that may be payable in relation to these proceedings, if any, so no provision has been recognized at 31 December 2015. In addition, no reliable estimate can be made of the amounts that may be payable in relation to any other securities litigation, if any, so no provision has been recognized at 31 December 2015.

Other litigation

In addition to the securities class actions described above, BP is named as a defendant in approximately 2,700 other civil lawsuits brought by individuals and corporations in US federal and state courts, as well as certain non-US jurisdictions, resulting from the Deepwater Horizon accident, the Gulf of Mexico oil spill, and the spill response efforts. Further actions may still be brought. Among other claims, these lawsuits assert claims for personal injury in connection with the accident and the spill response, commercial and economic injury, damage to real and personal property, breach of contract and violations of statutes, including, but not limited to, alleged violations of US securities and environmental statutes. In addition, claims have been received, primarily from business claimants, under the Oil Pollution Act of 1990 (OPA 90) in relation to the 2010 federal deepwater drilling moratoria. Furthermore, there are also uncertainties around the outcomes of any further litigation including by parties excluded from, or parties who opted out of, the PSC settlement. Until further fact and expert disclosures occur, court rulings clarify the issues in dispute, liability and damage trial activity nears or progresses, or other actions such as further possible settlements occur, it is not possible given these uncertainties to arrive at a range of outcomes or a reliable estimate of the liabilities that may accrue to BP in connection with or as a result of these lawsuits, nor is it possible to determine the timing of any payment that may arise. Therefore no amounts have been provided for these items as at 31 December 2015.

Settlement and other agreements

Under the settlement agreements with Anadarko and MOEX, the other working interest owners in the Macondo well at the time of the incident, and with Cameron International, the designer and manufacturer of the Deepwater Horizon blowout preventer, BP has agreed to indemnify Anadarko, MOEX and Cameron for certain claims arising from the accident. It is therefore possible that BP may face claims under these indemnities, but it is not currently possible to reliably measure, nor identify the timing of, any obligation in relation to such claims and therefore no amount has been provided as at 31 December 2015. There are also agreements indemnifying certain third-party contractors in relation to litigation costs and certain other claims. A contingent liability also exists in relation to other obligations under these agreements.

2. Significant event – Gulf of Mexico oil spill – continued

The magnitude and timing of all possible obligations in relation to the Gulf of Mexico oil spill continue to be subject to a high degree of uncertainty. Any such possible obligations are therefore contingent liabilities and, at present, it is not practicable to estimate their magnitude or possible timing of payment. Furthermore, other material unanticipated obligations may arise in future in relation to the incident.

Impact upon the group income statement

The amount of the provision recognized during the year can be reconciled to the charge to the income statement as follows:

				$ million
	2015	2014	2013	Cumulative since the incident
Net increase in provision	**11,886**	1,327	1,860	56,591
Change in discount rate relating to provisions	**(333)**	2	(5)	(314)
Costs charged directly to the income statement	**156**	114	136	4,514
Trust fund liability – discounted	**–**	–	–	19,580
Change in discounting relating to trust fund liability	**–**	–	–	283
Recognition of reimbursement asset, net	**–**	(662)	(1,542)	(20,000)
Settlements credited to the income statement	**–**	–	(19)	(5,681)
(Profit) loss before interest and taxation	**11,709**	781	430	54,973
Finance costs	**247**	38	39	478
(Profit) loss before taxation	**11,956**	819	469	55,451

The group income statement for 2015 includes a pre-tax charge of $11,956 million (2014 pre-tax charge of $819 million) in relation to the Gulf of Mexico oil spill. The costs charged within production and manufacturing expenses in 2015 include $9.4 billion for the amounts provided under the Agreements, as well as the ongoing costs of operating the Gulf Coast Restoration Organization (GCRO), business economic loss claims, claims administration costs, legal and litigation costs. Finance costs of $247 million (2014 $38 million) reflect the unwinding of the discount on payables and provisions. The cumulative amount charged to the income statement to date comprises spill response costs arising in the aftermath of the incident, amounts charged for the Agreements, GCRO operating costs, amounts charged upon initial recognition of the trust obligation, litigation, claims, environmental and legal costs not paid through the Trust and estimated obligations for future costs that can be estimated reliably at this time, net of settlements agreed with the co-owners of the Macondo well and other third parties.

The total amount recognized in the income statement is analysed in the table below.

				$ million
	2015	2014	2013	Cumulative since the incident
Trust fund liability – discounted	**–**	–	–	19,580
Change in discounting relating to trust fund liability	**–**	–	–	283
Recognition of reimbursement asset	**–**	(662)	(1,542)	(20,000)
Other	**–**	–	–	8
Total (credit) charge relating to the trust fund	**–**	(662)	(1,542)	(129)
Environmental – amount provided	**5,393**	190	47	8,527
– change in discount rate relating to provisions	**(149)**	2	(5)	(130)
– costs charged directly to the income statement	**59**	–	–	129
Total charge relating to environmental	**5,303**	192	42	8,526
Spill response – amount provided	**–**	–	(113)	11,465
– costs charged directly to the income statement	**–**	–	–	2,839
Total (credit) charge relating to spill response	**–**	–	(113)	14,304
Litigation and claims – amount provided, net of provision derecognized	**5,832**	1,137	1,926	32,428
– change in discount rate relating to provisions	**(74)**	–	–	(74)
– costs charged directly to the income statement	**–**	–	–	184
Total charge relating to litigation and claims	**5,758**	1,137	1,926	32,538
Clean Water Act penalties – amount provided	**661**	–	–	4,171
– change in discount rate relating to provisions	**(110)**	–	–	(110)
Total charge relating to Clean Water Act penalties	**551**	–	–	4,061
Other costs charged directly to the income statement	**97**	114	136	1,354
Settlements credited to the income statement	**–**	–	(19)	(5,681)
(Profit) loss before interest and taxation	**11,709**	781	430	54,973
Finance costs	**247**	38	39	478
(Profit) loss before taxation	**11,956**	819	469	55,451

The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident remains subject to uncertainty as described under *Provisions and contingent liabilities* above.

3. Non-current assets held for sale

On 15 January 2016 BP and Rosneft announced that they had signed a binding agreement to dissolve the German refining joint operation Ruhr Oel GmbH (ROG). The restructuring, which is expected to be completed in 2016, will result in the transfer of BP's interests, currently held via ROG, in the Bayernoil, MiRO Karlsruhe and PCK Schwedt refineries to Rosneft. In exchange, BP will take sole ownership of the Gelsenkirchen refinery and the solvent production facility DHC Solvent Chemie, both of which are also currently owned by ROG.

The major classes of assets and liabilities relating to BP's share of ROG's interests in the Bayernoil, MiRO Karlsruhe and PCK Schwedt refineries classified as held for sale at 31 December 2015 were:

	$ million
	2015
Assets	
Property, plant and equipment	**360**
Intangible assets	**3**
Inventories	**215**
Assets classified as held for sale	**578**
Liabilities	
Defined benefit pension plan and other post-retirement benefit plan deficits	**(97)**
Liabilities directly associated with assets classified as held for sale	**(97)**

The assets classified as held for sale are reported in the Downstream segment. The associated pension liabilities are reported in Other businesses and corporate.

There were no assets or liabilities classified as held for sale as at 31 December 2014.

4. Disposals and impairment

The following amounts were recognized in the income statement in respect of disposals and impairments.

			$ million
	2015	2014	2013
Gains on sale of businesses and fixed assets			
Upstream	**324**	405	371
Downstream	**316**	474	214
TNK-BP	**–**	–	12,500
Other businesses and corporate	**26**	16	30
	666	895	13,115

			$ million
	2015	2014	2013
Losses on sale of businesses and fixed assets			
Upstream	**124**	345	144
Downstream	**98**	401	78
Other businesses and corporate	**41**	3	8
	263	749	230
Impairment losses			
Upstream	**2,484**	6,737	1,255
Downstream	**265**	1,264	484
Other businesses and corporate	**155**	317	218
	2,904	8,318	1,957
Impairment reversals			
Upstream	**(1,080)**	(102)	(226)
Downstream	**(178)**	–	–
	(1,258)	(102)	(226)
Impairment and losses on sale of businesses and fixed assets	**1,909**	8,965	1,961

Disposals

Disposal proceeds and principal gains and losses on disposals by segment are described below.

			$ million
	2015	2014	2013
Proceeds from disposals of fixed assets	**1,066**	1,820	18,115
Proceeds from disposals of businesses, net of cash disposed	**1,726**	1,671	3,884
	2,792	3,491	21,999
By business			
Upstream	**769**	2,533	1,288
Downstream	**1,747**	864	3,991
TNK-BP	**–**	–	16,646
Other businesses and corporate	**276**	94	74
	2,792	3,491	21,999

4. Disposals and impairment – continued

At 31 December 2015, deferred consideration relating to disposals amounted to $41 million receivable within one year (2014 $1,137 million and 2013 $23 million) and $385 million receivable after one year (2014 $333 million and 2013 $1,374 million). In addition, contingent consideration receivable relating to disposals amounted to $292 million at 31 December 2015 (2014 $454 million and 2013 $953 million), see Note 29 for further information.

Upstream

In 2015, gains principally resulted from the sale of our interests in the Central Area Transmission System in the North Sea, and from adjustments to prior year disposals in Canada.

In 2014, gains principally resulted from the sale of certain onshore assets in the US, and the sale of certain interests in the Gulf of Mexico and the North Sea. Losses principally arose from adjustments to prior year disposals in Canada and the North Sea.

In 2013, gains principally resulted from the sale of certain of our interests in the central North Sea, and the Yacheng field in China.

Downstream

In 2015, gains principally resulted from the disposal of our investment in the UTA European fuel cards business and our Australian bitumen business.

In 2014, gains principally resulted from the disposal of our global aviation turbine oils business. Losses principally arose from costs associated with the decision to cease refining operations at Bulwer Island in Australia.

In 2013, gains principally resulted from the disposal of our global LPG business and closing adjustments on the sales of the Texas City and Carson refineries with their associated marketing and logistics assets.

TNK-BP

In 2013, BP disposed of its 50% interest in TNK-BP to Rosneft, resulting in a gain on disposal of $12,500 million.

Summarized financial information relating to the sale of businesses is shown in the table below. The principal transactions categorized as business disposals in 2015 were the sales of our interests in the Central Area Transmission System in the North Sea and in the UTA European fuel cards business. The principal transaction categorized as a business disposal in 2014 was the sale of certain of our interests on the North Slope of Alaska in our upstream business. The principal transactions categorized as business disposals in 2013 were the sales of the Texas City and Carson refineries with their associated marketing and logistics assets. Information relating to sales of fixed assets is excluded from the table.

			$ million
	2015	2014	2013
Non-current assets	**154**	1,452	2,124
Current assets	**80**	182	2,371
Non-current liabilities	**(70)**	(395)	(94)
Current liabilities	**(50)**	(65)	(62)
Total carrying amount of net assets disposed	**114**	1,174	4,339
Recycling of foreign exchange on disposal	**16**	(7)	23
Costs on disposal[a]	**8**	128	13
	138	1,295	4,375
Gains on sale of businesses	**446**	280	69
Total consideration	**584**	1,575	4,444
Consideration received (receivable)[b]	**1,116**	96	(414)
Proceeds from the sale of businesses related to completed transactions	**1,700**	1,671	4,030
Deposits[c]	**26**	–	(146)
Proceeds from the sale of businesses	**1,726**	1,671	3,884

[a] 2013 includes pension and other post-retirement benefit plan curtailment gains of $109 million.
[b] Consideration received from prior year business disposals or to be received from current year disposals. 2015 includes $1,079 million of proceeds from our Toledo refinery partner, Husky Energy, in place of capital commitments relating to the original divestment transaction that have not been subsequently sanctioned. 2013 includes contingent consideration of $475 million relating to the disposal of the Texas City refinery.
[c] Proceeds received in the current year in advance of business disposals, less deposits received in prior years in relation to business disposals completed in the current year.

Impairments

Impairment losses and impairment reversals in each segment are described below. For information on significant estimates and judgements made in relation to impairments see Impairment of property, plant and equipment, intangibles and goodwill within Note 1. For information on impairments recognized by joint ventures see Note 15.

Upstream

The 2015 impairment losses of $2,484 million included $761 million in Angola, of which $371 million related to the Greater Plutonio cash-generating unit (CGU), which has a recoverable amount of $2,222 million. Impairment losses also included $830 million in relation to CGUs in the North Sea, of which $328 million relates to the Andrew area CGU, which has a recoverable amount of $766 million. The impairment losses primarily arose as a result of a lower price environment in the near term, and were also affected to a lesser extent by certain technical reserves revisions and increases in decommissioning cost estimates. The 2015 impairment reversals of $1,080 million included $945 million in the North Sea business, of which $473 million related to the Eastern Trough Area Project (ETAP) CGU, which has a recoverable amount of $2,489 million. The impairment reversals mainly arose as a result of decreases in cost estimates and a reduction in the discount rate applied, offsetting the impact of lower prices in the near term. Impairment losses and reversals relate to producing assets. The recoverable amounts of the Greater Plutonio CGU, the Andrew area CGU, and the ETAP CGU are their values in use. See Impairment of property, plant and equipment, intangible assets and goodwill within Note 1 for further information on assumptions used for impairment testing. The discount rate used to determine the recoverable amount of the Greater Plutonio CGU included the 2% premium for higher-risk countries as described in Note 1; a premium was not applied in determining the recoverable amount of the other CGUs.

The 2014 impairment losses of $6,737 million included $4,876 million in relation to CGUs in the North Sea, of which $1,964 million related to the Valhall CGU, $660 million related to the Andrew area CGU, and $515 million related to the ETAP CGU. Impairment losses also included an $859-million impairment of our PSVM CGU in Angola, and a $415-million impairment of the Block KG D6 CGU in India. All of the impairments related to producing

4. Disposals and impairment – continued

assets. The impairments in the North Sea and Angola arose as a result of a lower price environment in the near term, technical reserves revisions, and increases in expected decommissioning cost estimates. The impairment of Block KG D6 arose following the introduction of a new formula for Indian gas prices. The discount rate used to determine the value in use of the PSVM CGU included the 2% premium for higher-risk countries. A premium was not applied in determining the recoverable amount of the other CGUs.

The main elements of the 2013 impairment losses of $1,255 million were a $251-million impairment loss relating to the Browse project in Australia and a $253-million aggregate write-down of a number of assets in the North Sea, caused by increases in expected decommissioning costs. Impairment reversals arose on certain of our interests in Alaska, the Gulf of Mexico, and the North Sea, triggered by reductions in decommissioning provisions due to continued review of the expected decommissioning costs and an increase in the discount rate for provisions.

Downstream

The 2015 impairment losses of $265 million arose principally in relation to certain manufacturing assets in our petrochemicals business and certain US midstream assets, where the expected disposal proceeds were lower than the book values.

The 2014 impairment losses of $1,264 million principally related to our Bulwer Island refinery and certain midstream assets in our fuels business, and certain manufacturing assets in our petrochemicals business.

The 2013 impairment losses of $484 million principally related to impairments of certain refineries in the US and elsewhere in our global fuels portfolio.

Other businesses and corporate

Impairment losses totalling $155 million, $317 million, and $218 million were recognized in 2015, 2014 and 2013 respectively. The amount for 2015 is principally in respect of our US wind business. The amount for 2014 is principally in respect of our biofuels businesses in the UK and US. The amount for 2013 is principally in respect of our US wind business.

5. Segmental analysis

The group's organizational structure reflects the various activities in which BP is engaged. At 31 December 2015, BP had three reportable segments: Upstream, Downstream and Rosneft.

Upstream's activities include oil and natural gas exploration, field development and production; midstream transportation, storage and processing; and the marketing and trading of natural gas, including liquefied natural gas (LNG), together with power and natural gas liquids (NGLs).

Downstream's activities include the refining, manufacturing, marketing, transportation, and supply and trading of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers.

During 2013, BP completed transactions for the sale of BP's interest in TNK-BP to Rosneft, and for BP's further investment in Rosneft. BP's interest in Rosneft is accounted for using the equity method and is reported as a separate operating segment, reflecting the way in which the investment is managed.

Other businesses and corporate comprises the biofuels and wind businesses, the group's shipping and treasury functions, and corporate activities worldwide.

The Gulf Coast Restoration Organization (GCRO), which manages aspects of our response to the 2010 Gulf of Mexico incident, was overseen by a board committee for all periods presented, however it is not an operating segment. Its costs are presented as a reconciling item between the sum of the results of the reportable segments and the group results. From 2016, we intend to report GCRO as part of Other businesses and corporate.

The accounting policies of the operating segments are the same as the group's accounting policies described in Note 1. However, IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker for the purposes of performance assessment and resource allocation. For BP, this measure of profit or loss is replacement cost profit or loss before interest and tax which reflects the replacement cost of supplies by excluding from profit or loss inventory holding gains and losses[a]. Replacement cost profit or loss for the group is not a recognized measure under IFRS.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenues and segment results include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers by region are based on the location of the group subsidiary which made the sale. The UK region includes the UK-based international activities of Downstream.

All surpluses and deficits recognized on the group balance sheet in respect of pension and other post-retirement benefit plans are allocated to Other businesses and corporate. However, the periodic expense relating to these plans is allocated to the operating segments based upon the business in which the employees work.

Certain financial information is provided separately for the US as this is an individually material country for BP, and for the UK as this is BP's country of domicile.

[a] Inventory holding gains and losses represent the difference between the cost of sales calculated using the replacement cost of inventory and the cost of sales calculated on the first-in first-out (FIFO) method after adjusting for any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on its historical cost of purchase or manufacture, rather than its replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed represent the difference between the charge to the income statement for inventory on a FIFO basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen based on the replacement cost of inventory. For this purpose, the replacement cost of inventory is calculated using data from each operation's production and manufacturing system, either on a monthly basis, or separately for each transaction where the system allows this approach. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions.

5. Segmental analysis – continued

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
							$ million
							2015
Segment revenues							
Sales and other operating revenues	43,235	200,569	–	2,048	–	(22,958)	222,894
Less: sales and other operating revenues between segments	(21,949)	(68)	–	(941)	–	22,958	–
Third party sales and other operating revenues	21,286	200,501	–	1,107	–	–	222,894
Earnings from joint ventures and associates – after interest and tax	192	491	1,330	(202)	–	–	1,811
Segment results							
Replacement cost profit (loss) before interest and taxation	(937)	7,111	1,310	(1,768)	(11,709)	(36)	(6,029)
Inventory holding gains (losses)[a]	(30)	(1,863)	4	–	–	–	(1,889)
Profit (loss) before interest and taxation	(967)	5,248	1,314	(1,768)	(11,709)	(36)	(7,918)
Finance costs							(1,347)
Net finance expense relating to pensions and other post-retirement benefits							(306)
Profit (loss) before taxation							(9,571)
Other income statement items							
Depreciation, depletion and amortization							
US	4,007	906	–	77	–	–	4,990
Non-US	8,866	1,162	–	201	–	–	10,229
Charges for provisions, net of write-back of unused provisions, including change in discount rate	824	611	–	228	11,553	–	13,216
Segment assets							
Investments in joint ventures and associates	8,304	3,214	5,797	519	–	–	17,834
Additions to non-current assets[b]	17,635	2,130	–	315	–	–	20,080
Additions to other investments							35
Element of acquisitions not related to non-current assets							(31)
Additions to decommissioning asset							(553)
Capital expenditure and acquisitions, on an accruals basis	17,082	2,109	–	340	–	–	19,531

[a] See explanation of inventory holding gains and losses on page 124.
[b] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

5. Segmental analysis – continued

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
							$ million
							2014
Segment revenues							
Sales and other operating revenues	65,424	323,486	–	1,989	–	(37,331)	353,568
Less: sales and other operating revenues between segments	(36,643)	173	–	(861)	–	37,331	–
Third party sales and other operating revenues	28,781	323,659	–	1,128	–	–	353,568
Earnings from joint ventures and associates – after interest and tax	1,089	265	2,101	(83)	–	–	3,372
Segment results							
Replacement cost profit (loss) before interest and taxation	8,934	3,738	2,100	(2,010)	(781)	641	12,622
Inventory holding gains (losses)[a]	(86)	(6,100)	(24)	–	–	–	(6,210)
Profit (loss) before interest and taxation	8,848	(2,362)	2,076	(2,010)	(781)	641	6,412
Finance costs							(1,148)
Net finance expense relating to pensions and other post-retirement benefits							(314)
Profit before taxation							4,950
Other income statement items							
Depreciation, depletion and amortization[b]							
US	4,129	984	–	97	–	–	5,210
Non-US	8,404	1,336	–	213	–	–	9,953
Charges for provisions, net of write-back of unused provisions, including change in discount rate	260	713	–	323	1,329	–	2,625
Segment assets							
Investments in joint ventures and associates	7,877	3,244	7,312	723	–	–	19,156
Additions to non-current assets[c]	22,587	3,121	–	784	–	–	26,492
Additions to other investments							160
Element of acquisitions not related to non-current assets							(366)
Additions to decommissioning asset							(2,505)
Capital expenditure and acquisitions, on an accruals basis	19,772	3,106	–	903	–	–	23,781

[a] See explanation of inventory holding gains and losses on page 124.
[b] It is estimated that the benefit arising from the absence of depreciation for the assets held for sale during the year was $221 million.
[c] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

5. Segmental analysis – continued

By business	Upstream	Downstream	Rosneft	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
								$ million
								2013
Segment revenues								
Sales and other operating revenues	70,374	351,195	–	–	1,805	–	(44,238)	379,136
Less: sales and other operating revenues between segments	(42,327)	(1,045)	–	–	(866)	–	44,238	–
Third party sales and other operating revenues	28,047	350,150	–	–	939	–	–	379,136
Earnings from joint ventures and associates – after interest and tax	1,027	195	2,058	–	(91)	–	–	3,189
Segment results								
Replacement cost profit (loss) before interest and taxation	16,657	2,919	2,153	12,500	(2,319)	(430)	579	32,059
Inventory holding gains (losses)[a]	4	(194)	(100)	–	–	–	–	(290)
Profit (loss) before interest and taxation	16,661	2,725	2,053	12,500	(2,319)	(430)	579	31,769
Finance costs								(1,068)
Net finance expense relating to pensions and other post-retirement benefits								(480)
Profit before taxation								30,221
Other income statement items								
Depreciation, depletion and amortization[b]								
US	3,538	747	–	–	181	–	–	4,466
Non-US	7,514	1,343	–	–	187	–	–	9,044
Charges for provisions, net of write-back of unused provisions, including change in discount rate	161	270	–	–	295	1,855	–	2,581
Segment assets								
Investments in joint ventures and associates	7,780	3,302	13,681	–	1,072	–	–	25,835
Additions to non-current assets[c]	19,499	4,449	11,941	–	1,027	–	–	36,916
Additions to other investments								41
Element of acquisitions not related to non-current assets								39
Additions to decommissioning asset								(384)
Capital expenditure and acquisitions, on an accruals basis	19,115	4,506	11,941	–	1,050	–	–	36,612

[a] See explanation of inventory holding gains and losses on page 124.
[b] It is estimated that the benefit arising from the absence of depreciation for the assets held for sale at 31 December 2012 until their disposal in 2013 amounted to approximately $201 million.
[c] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

5. Segmental analysis – continued

By geographical area	US	Non-US	$ million 2015 Total
Revenues			
Third party sales and other operating revenues[a]	**74,162**	**148,732**	**222,894**
Other income statement items			
Production and similar taxes	**215**	**821**	**1,036**
Results			
Replacement cost profit (loss) before interest and taxation	**(12,243)**	**6,214**	**(6,029)**
Non-current assets			
Non-current assets[b c]	**67,776**	**111,106**	**178,882**
Capital expenditure and acquisitions, on an accruals basis	**5,332**	**14,199**	**19,531**

[a] Non-US region includes UK $51,550 million.
[b] Non-US region includes UK $19,152 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

By geographical area	US	Non-US	$ million 2014 Total
Revenues			
Third party sales and other operating revenues[a]	122,951	230,617	353,568
Other income statement items			
Production and similar taxes	690	2,268	2,958
Results			
Replacement cost profit before interest and taxation	5,251	7,371	12,622
Non-current assets			
Non-current assets[b c]	69,125	114,462	183,587
Capital expenditure and acquisitions, on an accruals basis	7,227	16,554	23,781

[a] Non-US region includes UK $77,522 million.
[b] Non-US region includes UK $18,430 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

By geographical area	US	Non-US	$ million 2013 Total
Revenues			
Third party sales and other operating revenues[a]	128,764	250,372	379,136
Other income statement items			
Production and similar taxes	1,112	5,935	7,047
Results			
Replacement cost profit before interest and taxation	3,114	28,945	32,059
Non-current assets			
Non-current assets[b c]	70,228	124,439	194,667
Capital expenditure and acquisitions, on an accruals basis	9,176	27,436	36,612

[a] Non-US region includes UK $82,381 million.
[b] Non-US region includes UK $18,967 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

6. Income statement analysis

	2015	2014	$ million 2013
Interest and other income			
Interest income	**226**	258	282
Other income	**385**	585	495
	611	843	777
Currency exchange losses charged to the income statement[a]	**8**	36	180
Expenditure on research and development	**418**	663	707
Finance costs			
Interest payable	**1,065**	1,025	1,082
Capitalized at 1.75% (2014 1.94% and 2013 2%)[b]	**(179)**	(185)	(238)
Unwinding of discount on provisions and other payables	**461**	308	224
	1,347	1,148	1,068

[a] Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.
[b] Tax relief on capitalized interest is approximately $42 million (2014 $43 million and 2013 $62 million).

7. Exploration for and evaluation of oil and natural gas resources

The following financial information represents the amounts included within the group totals relating to activity associated with the exploration for and evaluation of oil and natural gas resources. All such activity is recorded within the Upstream segment.

For information on significant estimates and judgements made in relation to oil and natural gas accounting see Intangible assets within Note 1.

			$ million
	2015	2014	2013
Exploration and evaluation costs			
Exploration expenditure written off[a]	**1,829**	3,029	2,710
Other exploration costs	**524**	603	731
Exploration expense for the year	**2,353**	3,632	3,441
Impairment losses	**–**	–	253
Intangible assets – exploration and appraisal expenditure	**17,286**	19,344	20,865
Liabilities	**145**	227	212
Net assets	**17,141**	19,117	20,653
Capital expenditure, on an accruals basis	**1,197**	2,870	4,464
Net cash used in operating activities	**524**	603	731
Net cash used in investing activities	**1,216**	2,786	4,275

[a] 2015 included a $432-million write-off in Libya as there is significant uncertainty about the timing of future drilling operations. It also includes a $345-million write-off relating to the Gila discovery in the deepwater Gulf of Mexico and a $336-million write-off relating to the Pandora discovery in Angola as development of these prospects is considered challenging. 2014 included a $544-million write-off relating to disappointing appraisal results of Utica shale in the US Lower 48 and the subsequent decision not to proceed with its development plans, a $524-million write-off relating to the Bourarhat Sud block licence in the Illizi Basin of Algeria, a $395-million write-off relating to Block KG D6 in India and a $295-million write-off relating to the Moccasin discovery in the deepwater Gulf of Mexico. 2013 included a $845-million write-off relating to the value ascribed to Block BM-CAL-13 offshore Brazil as a result of the Pitanga exploration well not encountering commercial quantities of oil and gas and a $257-million write-off of costs relating to the Risha concession in Jordan as our exploration activities did not establish the technical basis for a development project in the concession. For further information see Upstream – Exploration on page 30.

The carrying amount, by location, of exploration and appraisal expenditure capitalized as intangible assets at 31 December 2015 is shown in the table below.

Carrying amount	Location
$1 - 2 billion	Angola; India
$2 - 3 billion	Canada; Egypt; Brazil
$3 - 4 billion	US – Gulf of Mexico

8. Taxation

Tax on profit

			$ million
	2015	2014	2013
Current tax			
Charge for the year	**1,910**	4,444	5,724
Adjustment in respect of prior years	**(329)**	48	61
	1,581	4,492	5,785
Deferred tax			
Origination and reversal of temporary differences in the current year	**(5,090)**	(3,194)	529
Adjustment in respect of prior years	**338**	(351)	149
	(4,752)	(3,545)	678
Tax charge (credit) on profit or loss	**(3,171)**	947	6,463

In 2015, the total tax charge recognized within other comprehensive income was $1,140 million (2014 $1,481 million credit and 2013 $1,374 million charge). See Note 31 for further information. The total tax charge recognized directly in equity was $9 million (2014 $36 million charge and 2013 $33 million credit).

For information on significant estimates and judgements made in relation to taxation see Income taxes within Note 1. For information on contingent liabilities in relation to taxation see Note 32.

Reconciliation of the effective tax rate

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective tax rate of the group on profit or loss before taxation. With effect from 1 April 2015 the UK statutory corporation tax rate reduced from 21% to 20% on profits arising from activities outside the North Sea.

For 2015, the items presented in the reconciliation are affected as a result of the overall tax credit for the year and the loss before taxation. In order to provide a more meaningful analysis of the effective tax rate, the table also presents separate reconciliations for the group excluding the impacts of the Gulf of Mexico oil spill and impairment losses, and for the impacts of the Gulf of Mexico oil spill and impairment losses in isolation.

For 2014, the items presented in the reconciliation are affected as a result of the tax credits related to the impairment losses recognized in the year and the effect of the impairment losses on the profit for the year. In order to provide a more meaningful analysis of the effective tax rate for 2014, the table also presents separate reconciliations for the group excluding the effects of the impairment losses, and for the effects of the impairment losses in isolation.

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8. Taxation – continued

For 2013, the effective tax rate is not affected significantly by impairment losses or the impact of the Gulf of Mexico oil spill.

							$ million
	2015 excluding impacts of Gulf of Mexico oil spill and impairments	**2015 impacts of Gulf of Mexico oil spill and impairments**	**2015**	2014 excluding impairments	2014 impacts of impairments	2014	2013
Profit (loss) before taxation	**4,031**	**(13,602)**	**(9,571)**	13,166	(8,216)	4,950	30,221
Tax charge (credit) on profit or loss	**945**	**(4,116)**	**(3,171)**	5,036	(4,089)	947	6,463
Effective tax rate	**23%**	**30%**	**33%**	38%	50%	19%	21%

							% of profit or loss before taxation
UK statutory corporation tax rate	**20**	**20**	**20**	21	21	21	23
Increase (decrease) resulting from							
UK supplementary and overseas taxes at higher or lower rates[a]	**–**	**18**	**25**	17	34	(11)	4
Tax reported in equity-accounted entities	**(10)**	**–**	**4**	(5)	–	(14)	(2)
Adjustments in respect of prior years	**1**	**–**	**–**	(2)	–	(6)	1
Movement in deferred tax not recognized	**17**	**(5)**	**(14)**	4	(3)	17	2
Tax incentives for investment	**(8)**	**–**	**3**	(4)	–	(10)	(2)
Gulf of Mexico oil spill non-deductible costs	**–**	**(2)**	**(3)**	–	–	1	–
Permanent differences relating to disposals	**(3)**	**–**	**1**	(1)	–	(1)	(8)
Foreign exchange	**18**	**–**	**(8)**	4	–	10	2
Items not deductible for tax purposes	**10**	**–**	**(4)**	4	(2)	12	1
Decrease in rate of UK supplementary charge[b]	**(23)**	**–**	**10**	–	–	–	–
Other	**1**	**(1)**	**(1)**	–	–	–	–
Effective tax rate	**23**	**30**	**33**	38	50	19	21

[a] For 2015 excluding impacts of the Gulf of Mexico oil spill and impairments, the most significant countries impacting upon the rate were the US (with an applicable statutory tax rate of 35%), Angola (50%), Germany (32%), Indonesia (42%) and UK North Sea (50%). However because there were profits in some countries and losses in others, the net impact on the effective tax rate reconciliation was less than 1%. For 2014 excluding impairments, jurisdictions which contribute significantly to this item are Angola (50%), Trinidad (55%) and the US (35%). For 2013, jurisdictions which contribute significantly are Angola, the UK North Sea and Trinidad, with applicable statutory tax rates of 50%, 62% and 55% respectively.
[b] For 2015, this relates to the one-off deferred tax impact of the enactment of legislation to reduce the UK supplementary charge tax rate applicable to profits arising in the North Sea from 32% to 20%.

Deferred tax

		$ million
Analysis of movements during the year in the net deferred tax liability	**2015**	2014
At 1 January	**11,584**	16,454
Exchange adjustments	**86**	122
Charge (credit) for the year in the income statement	**(4,752)**	(3,545)
Charge (credit) for the year in other comprehensive income	**1,140**	(1,563)
Charge (credit) for the year in equity	**9**	36
Acquisitions and disposals	**(13)**	80
At 31 December	**8,054**	11,584

The following table provides an analysis of deferred tax in the income statement and the balance sheet by category of temporary difference:

					$ million
		Income statement			Balance sheet
	2015	2014	2013	**2015**	2014
Deferred tax liability					
Depreciation	**(102)**	(2,178)	(474)	**28,712**	29,062
Pension plan surpluses	**84**	(272)	(691)	**878**	–
Derivative financial instruments	**(326)**	527	99	**961**	1,089
Other taxable temporary differences	**59**	(1,805)	(298)	**1,266**	1,356
	(285)	(3,728)	(1,364)	**31,817**	31,507
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**12**	492	787	**(1,972)**	(2,761)
Decommissioning, environmental and other provisions	**(2,513)**	52	1,385	**(13,737)**	(11,237)
Derivative financial instruments	**62**	166	30	**(710)**	(575)
Tax credits	**256**	589	(174)	**(43)**	(298)
Loss carry forward	**(2,239)**	(1,397)	(343)	**(5,985)**	(3,848)
Other deductible temporary differences	**(45)**	281	357	**(1,316)**	(1,204)
	(4,467)	183	2,042	**(23,763)**	(19,923)
Net deferred tax charge (credit) and net deferred tax liability	**(4,752)**	(3,545)	678	**8,054**	11,584
Of which – deferred tax liabilities				**9,599**	13,893
– deferred tax assets				**1,545**	2,309

8. Taxation – continued

The recognition of deferred tax assets of $1,067 million (2014 $1,467 million), in entities which have suffered a loss in either the current or preceding period, is supported by forecasts which indicate that sufficient future taxable profits will be available to utilize such assets.

A summary of temporary differences, unused tax credits and unused tax losses for which deferred tax has not been recognized is shown in the table below.

		$ billion
At 31 December	**2015**	2014
Unused US state tax losses[a]	**9.6**	9.0
Unused tax losses – other jurisdictions[b]	**2.1**	2.1
Unused tax credits	**20.4**	20.1
of which – arising in the UK[c]	**17.5**	18.0
– arising in the US[d]	**2.8**	2.0
Deductible temporary differences[e]	**23.2**	17.9
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	**3.9**	1.0

[a] Of the gross unused tax losses on which no deferred tax is recognized, $9.6 billion relates to US state taxes which expire in the period 2016-2035 with applicable tax rates ranging from 5% to 12%. An amendment has been made to the comparative amount.
[b] The majority of the unused tax losses have no fixed expiry date.
[c] The UK unused tax credits arise predominantly in overseas branches of UK entities based in jurisdictions with high tax rates. No deferred tax asset has been recognized on these tax credits as they are unlikely to have value in the future; UK taxes on these overseas branches are largely mitigated by double tax relief on the overseas tax. These tax credits have no fixed expiry date.
[d] The US unused tax credits expire in the period 2016-2025.
[e] Primarily comprises fixed asset temporary differences. Substantially all of the temporary differences have no expiry date.

			$ million
Impact of previously unrecognized deferred tax or write-down of deferred tax assets on current year charge	**2015**	2014	2013
Current tax benefit relating to the utilization of previously unrecognized tax credits and losses	**123**	171	216
Deferred tax benefit relating to the recognition of previously unrecognized tax credits and losses	**–**	–	178
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	**768**	153	–

9. Dividends

The quarterly dividend expected to be paid on 24 March 2016 in respect of the fourth quarter 2015 is 10 cents per ordinary share ($0.60 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 14 March 2016. A scrip dividend alternative is available, allowing shareholders to elect to receive their dividend in the form of new ordinary shares and ADS holders in the form of new ADSs.

	Pence per share			Cents per share			$ million		
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Dividends announced and paid in cash									
Preference shares							**2**	2	2
Ordinary shares									
March	**6.6699**	5.7065	6.0013	**10.00**	9.50	9.00	**1,708**	1,426	1,621
June	**6.5295**	5.8071	5.8342	**10.00**	9.75	9.00	**1,691**	1,572	1,399
September	**6.5488**	5.9593	5.7630	**10.00**	9.75	9.00	**1,717**	1,122	1,245
December	**6.6342**	6.3769	5.8008	**10.00**	10.00	9.50	**1,541**	1,728	1,174
	26.3824	23.8498	23.3993	**40.00**	39.00	36.50	**6,659**	5,850	5,441
Dividend announced, payable in March 2016				**10.00**			**1,841**		

The details of the scrip dividends issued are shown in the table below.

	2015	2014	2013
Number of shares issued (thousand)	**102,810**	165,644	202,124
Value of shares issued ($ million)	**642**	1,318	1,470

The financial statements for the year ended 31 December 2015 do not reflect the dividend announced on 2 February 2016 and expected to be paid in March 2016; this will be treated as an appropriation of profit in the year ended 31 December 2016.

10. Earnings per ordinary share

			Cents per share
	2015	2014	2013
Basic earnings per share	**(35.39)**	20.55	123.87
Diluted earnings per share	**(35.39)**	20.42	123.12

Basic earnings per ordinary share amounts are calculated by dividing the profit (loss) for the year attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. The average number of shares outstanding includes certain shares that will be issuable in the future under employee share-based payment plans and excludes treasury shares, which includes shares held by the Employee Share Ownership Plan trusts (ESOPs).

For the diluted earnings per share calculation, the weighted average number of shares outstanding during the year is adjusted for the average number of shares that are potentially issuable in connection with employee share-based payment plans using the treasury stock method. If the inclusion of potentially issuable shares would decrease loss per share, the potentially issuable shares are excluded from the weighted average number of shares outstanding used to calculate diluted earnings per share. A dilutive effect relating to potentially issuable shares has not been included, therefore, in the calculation of diluted earnings per share for 2015.

10. Earnings per ordinary share – continued

			$ million
	2015	2014	2013
Profit (loss) attributable to BP shareholders	**(6,482)**	3,780	23,451
Less: dividend requirements on preference shares	**2**	2	2
Profit (loss) for the year attributable to BP ordinary shareholders	**(6,484)**	3,778	23,449

			Shares thousand
	2015	2014	2013
Basic weighted average number of ordinary shares	**18,323,646**	18,385,458	18,931,021
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**–**	111,836	115,152
	18,323,646	18,497,294	19,046,173

The number of ordinary shares outstanding at 31 December 2015, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 18,412,392,432. Between 31 December 2015 and 16 February 2016, the latest practicable date before the completion of these financial statements, there was a net increase of 12,765,658 in the number of ordinary shares outstanding as a result of share issues in relation to employee share-based payment plans.

Employee share-based payment plans

The group operates share and share option plans for directors and certain employees to obtain ordinary shares and ADSs in the company. Information on these plans for directors is shown in the Directors remuneration report on pages 76-92.

The following table shows the number of shares potentially issuable under equity-settled employee share option plans, including the number of options outstanding, the number of options exercisable at the end of each year, and the corresponding weighted average exercise prices. The dilutive effect of these plans at 31 December is also shown.

Share options		**2015**		2014
	Number of options[a b] thousand	**Weighted average exercise price $**	Number of options[a b] thousand	Weighted average exercise price $
Outstanding	**70,049**	**8.54**	113,206	9.62
Exercisable	**46,520**	**10.21**	86,211	10.89
Dilutive effect	**2,659**	**n/a**	5,570	n/a

[a] Numbers of options shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).
[b] At 31 December 2015 the quoted market price of one BP ordinary share was £3.54 (2014 £4.11).

In addition, the group operates a number of equity-settled employee share plans under which share units are granted to the group's senior leaders and certain other employees. These plans typically have a three-year performance or restricted period during which the units accrue net notional dividends which are treated as having been reinvested. Leaving employment will normally preclude the conversion of units into shares, but special arrangements apply for participants that leave for qualifying reasons. The number of shares that are expected to vest each year under employee share plans are shown in the table below. The dilutive effect of the employee share plans at 31 December is also shown.

Share plans	**2015**	2014
Vesting	**Number of shares[a] thousand**	Number of shares[a] thousand
Within one year	**78,823**	78,467
1 to 2 years	**76,779**	91,993
2 to 3 years	**89,654**	80,966
3 to 4 years	**41,479**	28,564
4 to 5 years	**695**	222
	287,430	280,212
Dilutive effect	**101,984**	99,917

[a] Numbers of shares shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).

There has been a net increase of 60,530,268 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2015 and 16 February 2016.

11. Property, plant and equipment

$ million

	Land and land improvements	Buildings	Oil and gas properties[a]	Plant, machinery and equipment	Fixtures, fittings and office equipment	Transportation	Oil depots, storage tanks and service stations	Total
Cost								
At 1 January 2015	**3,415**	**3,061**	**200,514**	**48,815**	**3,031**	**13,819**	**9,046**	**281,701**
Exchange adjustments	**(259)**	**(144)**	**–**	**(1,828)**	**(89)**	**(61)**	**(772)**	**(3,153)**
Additions	**96**	**122**	**14,574**	**1,114**	**129**	**493**	**551**	**17,079**
Acquisitions	**–**	**–**	**–**	**27**	**–**	**–**	**–**	**27**
Transfers	**–**	**–**	**1,039**	**–**	**–**	**–**	**–**	**1,039**
Reclassified as assets held for sale	**–**	**(66)**	**–**	**(1,364)**	**(31)**	**–**	**–**	**(1,461)**
Deletions	**(58)**	**(96)**	**(561)**	**(1,020)**	**(174)**	**(213)**	**(407)**	**(2,529)**
At 31 December 2015	**3,194**	**2,877**	**215,566**	**45,744**	**2,866**	**14,038**	**8,418**	**292,703**
Depreciation								
At 1 January 2015	**639**	**1,197**	**111,175**	**21,358**	**1,983**	**8,933**	**5,724**	**151,009**
Exchange adjustments	**(10)**	**(51)**	**–**	**(914)**	**(56)**	**(33)**	**(452)**	**(1,516)**
Charge for the year	**37**	**135**	**12,004**	**1,760**	**238**	**426**	**323**	**14,923**
Impairment losses	**14**	**2**	**2,113**	**225**	**1**	**283**	**7**	**2,645**
Impairment reversals	**–**	**–**	**(1,079)**	**(2)**	**–**	**(18)**	**(159)**	**(1,258)**
Transfers	**–**	**–**	**21**	**–**	**–**	**–**	**–**	**21**
Reclassified as assets held for sale	**–**	**(33)**	**–**	**(1,038)**	**(24)**	**–**	**–**	**(1,095)**
Deletions	**(38)**	**(93)**	**(403)**	**(737)**	**(58)**	**(152)**	**(303)**	**(1,784)**
At 31 December 2015	**642**	**1,157**	**123,831**	**20,652**	**2,084**	**9,439**	**5,140**	**162,945**
Net book amount at 31 December 2015	**2,552**	**1,720**	**91,735**	**25,092**	**782**	**4,599**	**3,278**	**129,758**
Cost								
At 1 January 2014	3,375	3,027	187,691	48,912	3,176	13,314	9,961	269,456
Exchange adjustments	(284)	(105)	–	(1,737)	(93)	(44)	(871)	(3,134)
Additions	315	183	18,033	2,008	258	1,049	521	22,367
Acquisitions	31	22	–	252	3	–	–	308
Transfers	–	–	993	–	–	–	–	993
Deletions	(22)	(66)	(6,203)	(620)	(313)	(500)	(565)	(8,289)
At 31 December 2014	3,415	3,061	200,514	48,815	3,031	13,819	9,046	281,701
Depreciation								
At 1 January 2014	550	1,141	97,063	20,378	1,970	8,833	5,831	135,766
Exchange adjustments	(5)	(46)	–	(989)	(56)	(27)	(550)	(1,673)
Charge for the year	84	156	11,728	1,833	267	343	448	14,859
Impairment losses	15	–	6,304	625	–	179	504	7,627
Impairment reversals	–	–	(19)	–	–	(83)	–	(102)
Deletions	(5)	(54)	(3,901)	(489)	(198)	(312)	(509)	(5,468)
At 31 December 2014	639	1,197	111,175	21,358	1,983	8,933	5,724	151,009
Net book amount at 31 December 2014	2,776	1,864	89,339	27,457	1,048	4,886	3,322	130,692
Assets held under finance leases at net book amount included above								
At 31 December 2015	**–**	**2**	**84**	**297**	**–**	**242**	**–**	**625**
At 31 December 2014	–	3	135	295	–	244	–	677
Assets under construction included above								
At 31 December 2015								**27,755**
At 31 December 2014								26,429

[a] For information on significant estimates and judgements made in relation to the estimation of oil and natural reserves see Property, plant and equipment within Note 1.

12. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2015 amounted to $10,379 million (2014 $14,590 million – amended from $15,635 million previously disclosed). BP's share of capital commitments of joint ventures amounted to $586 million (2014 $369 million).

13. Goodwill and impairment review of goodwill

		$ million
	2015	2014
Cost		
At 1 January	**12,482**	12,851
Exchange adjustments	**(237)**	(278)
Acquisitions	**5**	73
Deletions	**(14)**	(164)
At 31 December	**12,236**	12,482
Impairment losses		
At 1 January	**614**	670
Deletions	**(5)**	(56)
At 31 December	**609**	614
Net book amount at 31 December	**11,627**	11,868
Net book amount at 1 January	**11,868**	12,181

Impairment review of goodwill

		$ million
Goodwill at 31 December	**2015**	2014
Upstream	**7,812**	7,819
Downstream	**3,761**	3,968
Other businesses and corporate	**54**	81
	11,627	11,868

Goodwill acquired through business combinations has been allocated to groups of cash-generating units that are expected to benefit from the synergies of the acquisition. For Upstream, goodwill is allocated to all oil and gas assets in aggregate at the segment level. For Downstream, goodwill has been allocated to Lubricants and Other.

For information on significant estimates and judgements made in relation to impairments see Impairment of property, plant and equipment, intangibles and goodwill within Note 1.

Upstream

		$ million
	2015	2014
Goodwill	**7,812**	7,819
Excess of recoverable amount over carrying amount	**12,894**	26,077

The table above shows the carrying amount of goodwill for the segment and the excess of the recoverable amount, based upon a fair value less costs of disposal calculation, over the carrying amount (the headroom).

The fair value less costs of disposal is based on the cash flows expected to be generated by the projected oil or natural gas production profiles up to the expected dates of cessation of production of each producing field, based on current estimates of reserves and resources, appropriately risked. Midstream and supply and trading activities and equity-accounted entities are generally not included in the impairment review of goodwill, because they are not part of the grouping of cash-generating units to which the goodwill relates and which is used to monitor the goodwill for internal management purposes. Where such activities form part of a wider Upstream cash-generating unit, they are reflected in the test. The fair value calculation is based primarily on level 3 inputs as defined by the IFRS 13 'Fair value measurement' hierarchy. As the production profile and related cash flows can be estimated from BP's experience, management believes that the estimated cash flows expected to be generated over the life of each field is the appropriate basis upon which to assess goodwill for impairment. The estimated date of cessation of production depends on the interaction of a number of variables, such as the recoverable quantities of hydrocarbons, the production profile of the hydrocarbons, the cost of the development of the infrastructure necessary to recover the hydrocarbons, production costs, the contractual duration of the production concession and the selling price of the hydrocarbons produced. As each producing field has specific reservoir characteristics and economic circumstances, the cash flows of the fields are computed using appropriate individual economic models and key assumptions agreed by BP management. Capital expenditure, operating costs and expected hydrocarbon production profiles are derived from the business segment plan adjusted for assumptions reflecting the price environment at the time that the test was performed. Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis are developed to be consistent with this. The production profiles used are consistent with the reserve and resource volumes approved as part of BP's centrally controlled process for the estimation of proved and probable reserves and total resources. Intangible assets are deemed to have a recoverable amount equal to their carrying amount.

Consistent with prior years, the 2015 review for impairment was carried out during the fourth quarter. The key assumptions used in the fair value less costs of disposal calculation are oil and natural gas prices, production volumes and the discount rate. Oil price assumptions for the first five years reflect the forward market prices at the time that the calculation was prepared. The prices used were, on average, $6.50 per barrel higher than the prices at the end of the year which are disclosed in Note 1. Gas price assumptions used for the first five years were, on average, the same as those disclosed in Note 1. Long-term price assumptions and discount rate assumptions used were as disclosed in Note 1. The fair value less costs of disposal calculations have been prepared solely for the purposes of determining whether the goodwill balance was impaired. Estimated future cash flows were prepared on the basis of certain assumptions prevailing at the time of the test. The actual outcomes may differ from the assumptions made. For example, reserves and resources estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change, and future commodity prices may differ from the forecasts used in the calculations.

13. Goodwill and impairment review of goodwill – continued

The sensitivities to different variables have been estimated using certain simplifying assumptions. For example, lower oil and gas prices sensitivities do not reflect the specific impacts for each contractual arrangement and will not capture fully any favourable impacts that may arise from cost deflation. Therefore a detailed calculation at any given price or production profile may produce a different result.

It is estimated that if the oil price assumption for all future years (the first five years, and the long-term assumption from 2021 onwards) was approximately $6.50 per barrel lower in each year, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the segment. It is estimated that if the gas price assumption for all future years was approximately $0.60 per mmbtu lower in each year, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the segment.

Estimated production volumes are based on detailed data for each field and take into account development plans agreed by management as part of the long-term planning process. The average production for the purposes of goodwill impairment testing over the next 15 years is 911mmboe per year (2014 847mmboe per year). It is estimated that if production volume were to be reduced by approximately 3% for this period, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment.

It is estimated that if the post-tax discount rate was approximately 9% for the entire portfolio, an increase of 2% for all countries not classified as 'higher risk', this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment.

Downstream

						$ million
			2015			2014
	Lubricants	**Other**	**Total**	Lubricants	Other	Total
Goodwill	**3,109**	**652**	**3,761**	3,264	704	3,968

Cash flows for each cash-generating unit are derived from the business segment plans, which cover a period of two to five years. To determine the value in use for each of the cash-generating units, cash flows for a period of 10 years are discounted and aggregated with a terminal value.

Lubricants

As permitted by IAS 36, the detailed calculations of Lubricants' recoverable amount performed in the most recent detailed calculation in 2013 were used for the 2015 impairment test as the criteria in that standard were considered satisfied: the headroom was substantial in 2013; there have been no significant changes in the assets and liabilities; and the likelihood that the recoverable amount would be less than the carrying amount at the time was remote.

The key assumptions to which the calculation of value in use for the Lubricants unit is most sensitive are operating unit margins, sales volumes, and discount rate. The values assigned to these key assumptions reflect BP's experience. No reasonably possible change in any of these key assumptions would cause the unit's carrying amount to exceed its recoverable amount. Cash flows beyond the two-year plan period were extrapolated using a nominal 3% growth rate.

14. Intangible assets

						$ million
			2015			2014
	Exploration and appraisal expenditure[a]	**Other intangibles**	**Total**	Exploration and appraisal expenditure[a]	Other intangibles	Total
Cost						
At 1 January	**21,723**	**4,268**	**25,991**	21,742	3,936	25,678
Exchange adjustments	**–**	**(187)**	**(187)**	–	(175)	(175)
Acquisitions	**–**	**–**	**–**	–	455	455
Additions	**1,197**	**234**	**1,431**	2,871	394	3,265
Transfers	**(1,039)**	**–**	**(1,039)**	(993)	–	(993)
Reclassified as assets held for sale	**–**	**(18)**	**(18)**	–	–	–
Deletions	**(2,025)**	**(242)**	**(2,267)**	(1,897)	(342)	(2,239)
At 31 December	**19,856**	**4,055**	**23,911**	21,723	4,268	25,991
Amortization						
At 1 January	**2,379**	**2,705**	**5,084**	877	2,762	3,639
Exchange adjustments	**–**	**(75)**	**(75)**	–	(72)	(72)
Charge for the year	**1,829**	**296**	**2,125**	3,029	304	3,333
Impairment losses	**–**	**–**	**–**	–	50	50
Transfers	**(21)**	**–**	**(21)**	–	–	–
Reclassified as assets held for sale	**–**	**(15)**	**(15)**	–	–	–
Deletions	**(1,617)**	**(230)**	**(1,847)**	(1,527)	(339)	(1,866)
At 31 December	**2,570**	**2,681**	**5,251**	2,379	2,705	5,084
Net book amount at 31 December	**17,286**	**1,374**	**18,660**	19,344	1,563	20,907
Net book amount at 1 January	**19,344**	**1,563**	**20,907**	20,865	1,174	22,039

[a] For further information see Intangible assets within Note 1 and Note 7.

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15. Investments in joint ventures

The following table provides aggregated summarized financial information relating to the group's share of joint ventures.

			$ million
	2015	2014	2013
Sales and other operating revenues	**9,588**	12,208	12,507
Profit before interest and taxation	**785**	1,210	1,076
Finance costs	**188**	125	130
Profit before taxation	**597**	1,085	946
Taxation	**625**	515	499
Profit (loss) for the year	**(28)**	570	447
Other comprehensive income	**(1)**	(15)	38
Total comprehensive income	**(29)**	555	485
Non-current assets	**11,163**	11,586	
Current assets	**2,515**	2,853	
Total assets	**13,678**	14,439	
Current liabilities	**1,855**	2,222	
Non-current liabilities	**3,500**	3,774	
Total liabilities	**5,355**	5,996	
Net assets	**8,323**	8,443	
Group investment in joint ventures			
Group share of net assets (as above)	**8,323**	8,443	
Loans made by group companies to joint ventures	**89**	310	
	8,412	8,753	

The loss for the year shown in the table above includes $711 million relating to BP's share of impairment losses recognized by joint ventures, a significant element of which relates to the Angola LNG plant.

Transactions between the group and its joint ventures are summarized below.

						$ million
Sales to joint ventures		**2015**		2014		2013
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	**2,841**	**245**	3,148	300	4,125	342

						$ million
Purchases from joint ventures		**2015**		2014		2013
Product	**Purchases**	**Amount payable at 31 December**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**861**	**104**	907	129	503	51

The terms of the outstanding balances receivable from joint ventures are typically 30 to 45 days. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts. Dividends receivable are not included in the table above.

16. Investments in associates

The following table provides aggregated summarized financial information for the group's associates as it relates to the amounts recognized in the group income statement and on the group balance sheet.

					$ million
		Income statement			Balance sheet
		Earnings from associates – after interest and tax			Investments in associates
	2015	2014	2013	**2015**	2014
Rosneft	**1,330**	2,101	2,058	**5,797**	7,312
Other associates	**509**	701	684	**3,625**	3,091
	1,839	2,802	2,742	**9,422**	10,403

The associate that is material to the group at both 31 December 2015 and 2014 is Rosneft. In 2013, BP sold its 50% interest in TNK-BP to Rosneft and increased its investment in Rosneft. The net cash inflow in 2013 relating to the transaction included in Net cash used in investing activities in the cash flow statement was $11.8 billion. From 22 October 2012, the investment in TNK-BP was classified as an asset held for sale and, therefore, equity accounting ceased. Profits of approximately $738 million were not recognized in 2013 as a result of the discontinuance of equity accounting.

16. Investments in associates – continued

Since 21 March 2013, BP has owned 19.75% of the voting shares of Rosneft. Rosneft shares are listed on the MICEX stock exchange in Moscow and its global depository receipts are listed on the London Stock Exchange. The Russian federal government, through its investment company OJSC Rosneftegaz, owned 69.5% of the voting shares of Rosneft at 31 December 2015.

BP classifies its investment in Rosneft as an associate because, in management's judgement, BP has significant influence over Rosneft; see Note 1 – Interests in other entities – Significant estimate or judgement: accounting for interests in other entities. The group's investment in Rosneft is a foreign operation whose functional currency is the Russian rouble. The reduction in the group's equity-accounted investment balance for Rosneft at 31 December 2015 compared with 31 December 2014 was principally due to the weakening of the rouble compared to the US dollar, the effects of which have been recognized in other comprehensive income.

The value of BP's 19.75% shareholding in Rosneft based on the quoted market share price of $3.48 per share (2014 $3.51 per share) was $7,283 million at 31 December 2015 (2014 $7,346 million).

The following table provides summarized financial information relating to Rosneft. This information is presented on a 100% basis and reflects adjustments made by BP to Rosneft's own results in applying the equity method of accounting. BP adjusts Rosneft's results for the accounting required under IFRS relating to BP's purchase of its interest in Rosneft and the amortization of the deferred gain relating to the disposal of BP's interest in TNK-BP. These adjustments have increased the reported profit for 2015, as shown in the table below, compared with the equivalent amount in Russian roubles that we expect Rosneft to report in its own financial statements under IFRS.

			$ million
			Gross amount
	2015	2014	2013
Sales and other operating revenues	**84,071**	142,856	122,866
Profit before interest and taxation	**12,253**	19,367	14,106
Finance costs	**3,696**	5,230	1,337
Profit before taxation	**8,557**	14,137	12,769
Taxation	**1,792**	3,428	2,137
Non-controlling interests	**30**	71	213
Profit for the year	**6,735**	10,638	10,419
Other comprehensive income	**(4,111)**	(13,038)	(441)
Total comprehensive income	**2,624**	(2,400)	9,978
Non-current assets	**84,689**	101,073	
Current assets	**34,891**	38,278	
Total assets	**119,580**	139,351	
Current liabilities	**25,691**	36,400	
Non-current liabilities	**63,554**	65,266	
Total liabilities	**89,245**	101,666	
Net assets	**30,335**	37,685	
Less: non-controlling interests	**982**	663	
	29,353	37,022	

The group received dividends, net of withholding tax, of $271 million from Rosneft in 2015 (2014 dividends of $693 million and 2013 dividends of $456 million).

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16. Investments in associates – continued

Summarized financial information for the group's share of associates is shown below.

									$ million
									BP share
			2015			2014			2013
	Rosneft[a]	**Other**	**Total**	Rosneft[a]	Other	Total	Rosneft	Other	Total
Sales and other operating revenues	**16,604**	**6,000**	**22,604**	28,214	9,724	37,938	24,266	12,998	37,264
Profit before interest and taxation	**2,420**	**661**	**3,081**	3,825	938	4,763	2,786	908	3,694
Finance costs	**730**	**6**	**736**	1,033	7	1,040	264	11	275
Profit before taxation	**1,690**	**655**	**2,345**	2,792	931	3,723	2,522	897	3,419
Taxation	**354**	**146**	**500**	677	230	907	422	213	635
Non-controlling interests	**6**	**–**	**6**	14	–	14	42	–	42
Profit for the year	**1,330**	**509**	**1,839**	2,101	701	2,802	2,058	684	2,742
Other comprehensive income	**(812)**	**(2)**	**(814)**	(2,575)	10	(2,565)	(87)	2	(85)
Total comprehensive income	**518**	**507**	**1,025**	(474)	711	237	1,971	686	2,657
Non-current assets	**16,726**	**3,914**	**20,640**	19,962	2,975	22,937			
Current assets	**6,891**	**1,621**	**8,512**	7,560	2,199	9,759			
Total assets	**23,617**	**5,535**	**29,152**	27,522	5,174	32,696			
Current liabilities	**5,074**	**1,134**	**6,208**	7,189	1,614	8,803			
Non-current liabilities	**12,552**	**1,311**	**13,863**	12,890	921	13,811			
Total liabilities	**17,626**	**2,445**	**20,071**	20,079	2,535	22,614			
Net assets	**5,991**	**3,090**	**9,081**	7,443	2,639	10,082			
Less: non-controlling interests	**194**	**–**	**194**	131	–	131			
	5,797	**3,090**	**8,887**	7,312	2,639	9,951			
Group investment in associates									
Group share of net assets (as above)	**5,797**	**3,090**	**8,887**	7,312	2,639	9,951			
Loans made by group companies to associates	**–**	**535**	**535**	–	452	452			
	5,797	**3,625**	**9,422**	7,312	3,091	10,403			

[a] From 1 October 2014, Rosneft adopted hedge accounting in relation to a portion of highly probable future export revenue denominated in US dollars over a five-year period. Foreign exchange gains and losses arising on the retranslation of borrowings denominated in currencies other than the Russian rouble and designated as hedging instruments are recognized initially in other comprehensive income, and are reclassified to the income statement as the hedged revenue is recognized.

Transactions between the group and its associates are summarized below.

						$ million
Sales to associates		**2015**		2014		2013
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	**5,302**	**1,058**	9,589	1,258	5,170	783

						$ million
Purchases from associates		**2015**		2014		2013
Product	**Purchases**	**Amount payable at 31 December**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
Crude oil and oil products, natural gas, transportation tariff	**11,619**	**2,026**	22,703	2,307	21,205	3,470

In addition to the transactions shown in the table above, in 2015 the group acquired a 20% participatory interest in Taas-Yuryakh Neftegazodobycha, a Rosneft subsidiary.

The terms of the outstanding balances receivable from associates are typically 30 to 45 days. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts. Dividends receivable are not included in the table above.

The majority of the sales to and purchases from associates relate to crude oil and oil products transactions with Rosneft.

BP has commitments amounting to $11,446 million (2014 $6,946 million), primarily in relation to contracts with its associates for the purchase of transportation capacity.

17. Other investments

				$ million
		2015		2014
	Current	**Non-current**	Current	Non-current
Equity investments[a]	**–**	**397**	–	420
Other	**219**	**605**	329	808
	219	**1,002**	329	1,228

[a] The majority of equity investments are unlisted.

Other non-current investments includes $605 million relating to life insurance policies (2014 $599 million) which have been designated as financial assets at fair value through profit and loss and their valuation methodology is in level 3 of the fair value hierarchy.

18. Inventories

		$ million
	2015	2014
Crude oil	**3,467**	5,614
Natural gas	**251**	285
Refined petroleum and petrochemical products	**7,470**	8,975
	11,188	14,874
Supplies	**2,626**	3,051
	13,814	17,925
Trading inventories	**328**	448
	14,142	18,373
Cost of inventories expensed in the income statement	**164,790**	281,907

The inventory valuation at 31 December 2015 is stated net of a provision of $1,295 million (2014 $2,879 million) to write inventories down to their net realizable value. The net credit to the income statement in the year in respect of inventory net realizable value provisions was $1,507 million (2014 $2,625 million charge).

Trading inventories are valued using quoted benchmark bid prices adjusted as appropriate for location and quality differentials. As such they are predominantly categorized within level 2 of the fair value hierarchy.

19. Trade and other receivables

				$ million
		2015		2014
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**13,682**	**72**	19,671	166
Amounts receivable from joint ventures and associates	**1,303**	**–**	1,558	–
Other receivables	**5,908**	**1,249**	7,863	1,293
	20,893	**1,321**	29,092	1,459
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**686**	**–**	1,154	2,701
Other receivables	**744**	**895**	792	627
	1,430	**895**	1,946	3,328
	22,323	**2,216**	31,038	4,787

[a] See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 28 for further information.

20. Valuation and qualifying accounts

						$ million
		2015		2014		2013
	Accounts receivable	**Fixed asset investments**	Accounts receivable	Fixed asset investments	Accounts receivable	Fixed asset investments
At 1 January	**331**	**517**	343	168	489	349
Charged to costs and expenses	**243**	**195**	127	438	82	4
Charged to other accounts[a]	**(23)**	**(4)**	(24)	(2)	(4)	4
Deductions	**(104)**	**(273)**	(115)	(87)	(224)	(189)
At 31 December	**447**	**435**	331	517	343	168

[a] Principally exchange adjustments.

Valuation and qualifying accounts comprise impairment provisions for accounts receivable and fixed asset investments, and are deducted in the balance sheet from the assets to which they apply.

For information on significant estimates and judgements made in relation to the recoverability of trade receivables see Impairment of loans and receivables within Note 1.

21. Trade and other payables

				$ million
		2015		2014
	Current	Non-current	Current	Non-current
Financial liabilities				
Trade payables	**16,838**	**–**	23,074	–
Amounts payable to joint ventures and associates	**2,130**	**–**	2,436	–
Other payables	**10,775**	**2,351**	11,832	2,985
	29,743	**2,351**	37,342	2,985
Non-financial liabilities				
Other payables	**2,206**	**559**	2,776	602
	31,949	**2,910**	40,118	3,587

Trade and other payables are predominantly interest free. See Note 28 for further information.

22. Provisions

						$ million
	Decommissioning	Environmental	Litigation and claims	Clean Water Act penalties	Other	Total
At 1 January 2015	**18,720**	**2,847**	**4,739**	**3,510**	**3,082**	**32,898**
Exchange adjustments	**(356)**	**(18)**	**(9)**	**–**	**(119)**	**(502)**
New or increased provisions	**972**	**5,697**	**6,058**	**661**	**1,506**	**14,894**
Write-back of unused provisions	**–**	**(75)**	**(24)**	**–**	**(274)**	**(373)**
Unwinding of discount	**167**	**106**	**62**	**68**	**13**	**416**
Change in discount rate[a]	**–**	**(149)**	**(74)**	**(110)**	**–**	**(333)**
Utilization	**(37)**	**(392)**	**(3,494)**	**–**	**(598)**	**(4,521)**
Reclassified to other payables	**(500)**	**(459)**	**(124)**	**–**	**(204)**	**(1,287)**
Deletions	**(20)**	**–**	**–**	**–**	**(58)**	**(78)**
At 31 December 2015	**18,946**	**7,557**	**7,134**	**4,129**	**3,348**	**41,114**
Of which – current	**703**	**587**	**3,023**	**–**	**841**	**5,154**
– non-current	**18,243**	**6,970**	**4,111**	**4,129**	**2,507**	**35,960**
Of which – Gulf of Mexico oil spill[b]	**–**	**5,919**	**6,459**	**4,129**	**–**	**16,507**

[a] Provisions for the agreements to settle all federal and state claims in relation to the Gulf of Mexico oil spill are discounted using a discount rate equal to a current interest rate that the group could obtain for a borrowing on similar terms.
[b] Further information on the financial impacts of the Gulf of Mexico oil spill is provided in Note 2.

The decommissioning provision comprises the future cost of decommissioning oil and natural gas wells, facilities and related pipelines. The environmental provision includes provisions for costs related to the control, abatement, clean-up or elimination of environmental pollution relating to soil, groundwater, surface water and sediment contamination. The litigation and claims category includes provisions for matters related to, for example, commercial disputes, product liability, and allegations of exposures of third parties to toxic substances. Included within the other category at 31 December 2015 are provisions for deferred employee compensation of $484 million (2014 $553 million).

For information on significant estimates and judgements made in relation to provisions, including those for the Gulf of Mexico oil spill, see Provisions, contingencies and reimbursement assets within Note 1.

23. Pensions and other post-retirement benefits

Most group companies have pension plans, the forms and benefits of which vary with conditions and practices in the countries concerned. Pension benefits may be provided through defined contribution plans (money purchase schemes) or defined benefit plans (final salary and other types of schemes with committed pension benefit payments). For defined contribution plans, retirement benefits are determined by the value of funds arising from contributions paid in respect of each employee. For defined benefit plans, retirement benefits are based on such factors as an employee's pensionable salary and length of service. Defined benefit plans may be funded or unfunded. The assets of funded plans are generally held in separately administered trusts.

For information on significant estimates and judgements made in relation to accounting for these plans see Pensions and other post-retirement benefits within Note 1.

The primary pension arrangement in the UK is a funded final salary pension plan under which retired employees draw the majority of their benefit as an annuity. This pension plan is governed by a corporate trustee whose board is composed of four member-nominated directors, four company-nominated directors, including an independent director and an independent chairman nominated by the company. The trustee board is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as investment policies of the plan. The UK plan is closed to new joiners but remains open to ongoing accrual for current members. New joiners in the UK are eligible for membership of a defined contribution plan.

In the US, all employees who previously accrued pension benefits under a final salary plan now accrue benefits from 2015 onwards under a cash balance formula instead. Benefits previously accrued under final salary formulas are legally protected. Retired US employees typically take their pension benefit in the form of a lump sum payment upon retirement. The plan is funded and its assets are overseen by a fiduciary investment committee composed of six BP employees appointed by the president of BP Corporation North America Inc. (the appointing officer). The investment committee is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as the investment policies of the plan. US employees are also eligible to participate in a defined contribution (401k) plan in which employee contributions are matched with company contributions. In the US, group companies also provide post-retirement healthcare to retired employees and their dependants (and, in certain cases, life insurance coverage); the entitlement to these benefits is usually based on the employee remaining in service until a specified age and completion of a minimum period of service.

23. Pensions and other post-retirement benefits – continued

In the Eurozone, there are defined benefit pension plans in Germany, France, the Netherlands and other countries. In Germany and France, the majority of the pensions are unfunded, in line with market practice. In Germany, the group's largest Eurozone plan, employees receive a pension and also have a choice to supplement their core pension through salary sacrifice. For employees who joined since 2002 the core pension benefit is a career average plan with retirement benefits based on such factors as an employee's pensionable salary and length of service. The returns on the notional contributions made by both the company and employees are set out in German tax law. Retired German employees take their pension benefit typically in the form of an annuity. The German plan is governed by legal agreements between BP and the works council or between BP and the trade union.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2015 the aggregate level of contributions was $1,066 million (2014 $1,252 million and 2013 $1,272 million). The aggregate level of contributions in 2016 is expected to be approximately $1,050 million, and includes contributions in all countries that we expect to be required to make contributions by law or under contractual agreements, as well as an allowance for discretionary funding.

For the primary UK plan there is a funding agreement between the group and the trustee. On an annual basis the latest funding position is reviewed and a schedule of contributions covering the next seven years is agreed. The funding agreement can be terminated unilaterally by either party with two years' notice. Contractually committed funding therefore represents nine years of future contributions, which amounted to $4,374 million at 31 December 2015, of which $1,437 million relates to past service. This amount is included in the group's committed cash flows relating to pensions and other post-retirement benefit plans as set out in the table of contractual obligations on page 220. The surplus relating to the primary UK pension plan is recognized on the balance sheet on the basis that the company is entitled to a refund of any remaining assets once all members have left the plan.

Pension contributions in the US are determined by legislation and are supplemented by discretionary contributions. All of the contributions made into the US pension plan in 2015 were discretionary and no statutory funding requirement is expected in the next 12 months.

There was no minimum funding requirement for the US plan, and no significant minimum funding requirements in other countries at 31 December 2015.

The obligation and cost of providing pensions and other post-retirement benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2015. The UK plans are subject to a formal actuarial valuation every three years; valuations are required more frequently in many other countries. The most recent formal actuarial valuation of the UK pension plans was as at 31 December 2014. A valuation of the US plan is carried out annually.

The material financial assumptions used to estimate the benefit obligations of the various plans are set out below. The assumptions are reviewed by management at the end of each year, and are used to evaluate the accrued benefit obligation at 31 December and pension expense for the following year.

			%						
Financial assumptions used to determine benefit obligation			UK			US			Eurozone
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Discount rate for plan liabilities	**3.9**	3.6	4.6	**4.0**	3.7	4.3	**2.4**	2.0	3.6
Rate of increase in salaries	**4.4**	4.5	5.1	**3.9**	4.0	3.9	**3.2**	3.4	3.4
Rate of increase for pensions in payment	**3.0**	3.0	3.3	**–**	–	–	**1.6**	1.8	1.8
Rate of increase in deferred pensions	**3.0**	3.0	3.3	**–**	–	–	**0.6**	0.7	0.7
Inflation for plan liabilities	**3.0**	3.0	3.3	**1.5**	1.6	2.1	**1.8**	2.0	2.0

			%						
Financial assumptions used to determine benefit expense			UK			US			Eurozone
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Discount rate for plan service cost	**3.9**	4.8	4.4	**3.8**	4.6	3.3	**2.3**	3.9	3.5
Discount rate for plan other finance expense	**3.6**	4.6	4.4	**3.7**	4.3	3.3	**2.0**	3.6	3.5
Inflation for plan service cost	**3.1**	3.4	3.1	**1.6**	2.1	2.4	**2.0**	2.0	2.0

The discount rate assumptions are based on third-party AA corporate bond indices and for our largest plans in the UK, US and the Eurozone we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumptions for our UK and US plans are based on the difference between the yields on index-linked and fixed-interest long-term government bonds. In other countries, including the Eurozone, we use one of these approaches, or advice from the local actuary depending on the information available. The inflation assumptions are used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions where there is such an increase.

The assumptions for the rate of increase in salaries are based on the inflation assumption plus an allowance for expected long-term real salary growth. These include allowance for promotion-related salary growth, of up to 1.0% depending on country.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. The mortality assumptions reflect best practice in the countries in which we provide pensions, and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. BP's most substantial pension liabilities are in the UK, the US and the Eurozone where our mortality assumptions are as follows:

			Years						
Mortality assumptions			UK			US			Eurozone
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Life expectancy at age 60 for a male currently aged 60	**28.5**	28.3	27.8	**25.7**	25.6	24.9	**24.9**	24.7	24.4
Life expectancy at age 60 for a male currently aged 40	**31.0**	30.9	30.7	**27.5**	27.4	26.4	**27.5**	27.3	26.9
Life expectancy at age 60 for a female currently aged 60	**29.5**	29.4	29.5	**29.2**	29.1	26.5	**28.8**	28.7	28.5
Life expectancy at age 60 for a female currently aged 40	**31.9**	31.8	32.2	**30.9**	30.9	27.3	**31.2**	31.1	30.7

Pension plan assets are generally held in trusts. The primary objective of the trusts is to accumulate pools of assets sufficient to meet the obligations of the various plans. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

23. Pensions and other post-retirement benefits – continued

A significant proportion of the assets are held in equities, which are expected to generate a higher level of return over the long term, with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified.

For the primary UK pension plan there is an agreement with the trustee to reduce the proportion of plan assets held as equities and increase the proportion held as bonds over time, with a view to better matching the asset portfolio with the pension liabilities. There is a similar agreement in place in the US. During 2015, the UK and the US plans switched 8% and 5% respectively from equities to bonds.

In 2015, BP's primary plan in the UK adopted a more formal liability driven investment (LDI) approach for part of the portfolio, a form of investing designed to match the movement in pension plan assets with the impact of interest rate changes and inflation assumption changes on the projected benefit obligation.

The current asset allocation policy for the major plans at 31 December 2015 was as follows:

Asset category	UK %	US %
Total equity (including private equity)	**62**	**55**
Bonds/cash (including LDI)	**31**	**45**
Property/real estate	**7**	**–**

The amounts invested under the LDI programme as at 31 December 2015 were $329 million of government-issued nominal bonds and $6,421 million of index-linked bonds. This is partly funded by short-term sale and repurchase agreements, proceeds from which are shown separately in the table below.

In addition, the primary UK plan entered into interest rate swaps in the year to offset the long-term fixed interest rate exposure for $2,651 million of the corporate bond portfolio. The $17 million fair value of the swaps as at 31 December 2015 is included in other assets in the table below.

Some of the group's pension plans in other countries also use derivative financial instruments as part of their asset mix to manage the level of risk.

The group's main pension plans do not invest directly in either securities or property/real estate of the company or of any subsidiary.

The fair values of the various categories of assets held by the defined benefit plans at 31 December are presented in the table below, including the effects of derivative financial instruments. Movements in the fair value of plan assets during the year are shown in detail in the table on page 143.

$ million

	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2015					
Listed equities – developed markets	**13,474**	**2,329**	**423**	**371**	**16,597**
– emerging markets	**2,305**	**226**	**49**	**50**	**2,630**
Private equity	**2,933**	**1,522**	**1**	**4**	**4,460**
Government issued nominal bonds	**393**	**1,527**	**685**	**492**	**3,097**
Government issued index-linked bonds	**6,425**	**–**	**5**	**–**	**6,430**
Corporate bonds	**4,357**	**1,717**	**551**	**367**	**6,992**
Property	**2,453**	**6**	**48**	**58**	**2,565**
Cash	**564**	**116**	**10**	**139**	**829**
Other	**110**	**67**	**102**	**50**	**329**
Debt (repurchase agreements) used to fund liability driven investments	**(1,791)**	**–**	**–**	**–**	**(1,791)**
	31,223	**7,510**	**1,874**	**1,531**	**42,138**
At 31 December 2014					
Listed equities – developed markets	16,190	3,026	415	420	20,051
– emerging markets	2,719	293	45	47	3,104
Private equity	2,983	1,571	2	26	4,582
Government issued nominal bonds	642	1,535	753	604	3,534
Government issued index-linked bonds	892	–	9	–	901
Corporate bonds	4,687	1,726	541	340	7,294
Property	2,403	7	51	69	2,530
Cash	1,145	134	85	191	1,555
Other	112	63	72	38	285
	31,773	8,355	1,973	1,735	43,836
At 31 December 2013					
Listed equities – developed markets	17,341	3,260	414	499	21,514
– emerging markets	2,290	308	32	52	2,682
Private equity	2,907	1,432	2	4	4,345
Government issued nominal bonds	549	1,259	717	541	3,066
Government issued index-linked bonds	787	–	12	57	856
Corporate bonds	4,427	1,323	597	385	6,732
Property	2,200	6	57	77	2,340
Cash	855	135	120	158	1,268
Other	160	55	64	49	328
	31,516	7,778	2,015	1,822	43,131

[a] Bonds held by the UK pension plans are all denominated in sterling. Property held by the UK pension plans is in the United Kingdom.
[b] Bonds held by the US pension plans are denominated in US dollars.

	UK	US	Eurozone	Other	Total
					$ million
					2015
Analysis of the amount charged to profit (loss) before interest and taxation					
Current service cost[a]	485	371	96	96	1,048
Past service cost[b]	12	(27)	47	(7)	25
Settlement	–	–	(1)	(3)	(4)
Operating charge relating to defined benefit plans	497	344	142	86	1,069
Payments to defined contribution plans	31	205	8	41	285
Total operating charge	528	549	150	127	1,354
Interest income on plan assets[a]	(1,124)	(289)	(37)	(55)	(1,505)
Interest on plan liabilities	1,146	423	151	91	1,811
Other finance expense	22	134	114	36	306
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	315	(139)	25	33	234
Change in financial assumptions underlying the present value of the plan liabilities	2,054	607	592	213	3,466
Change in demographic assumptions underlying the present value of the plan liabilities	–	60	15	–	75
Experience gains and losses arising on the plan liabilities	336	(48)	47	29	364
Remeasurements recognized in other comprehensive income	2,705	480	679	275	4,139
Movements in benefit obligation during the year					
Benefit obligation at 1 January	32,416	11,875	8,327	2,638	55,256
Exchange adjustments	(1,451)	–	(843)	(294)	(2,588)
Operating charge relating to defined benefit plans	497	344	142	86	1,069
Interest cost	1,146	423	151	91	1,811
Contributions by plan participants[c]	32	–	2	5	39
Benefit payments (funded plans)[d]	(1,269)	(1,124)	(81)	(178)	(2,652)
Benefit payments (unfunded plans)[d]	(7)	(256)	(306)	(26)	(595)
Acquisitions	–	–	–	9	9
Reclassified as assets held for sale	–	–	(98)	–	(98)
Remeasurements	(2,390)	(619)	(654)	(242)	(3,905)
Benefit obligation at 31 December[a e]	28,974	10,643	6,640	2,089	48,346
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	31,773	8,355	1,973	1,735	43,836
Exchange adjustments	(1,506)	–	(205)	(186)	(1,897)
Interest income on plan assets[a]	1,124	289	37	55	1,505
Contributions by plan participants[c]	32	–	2	5	39
Contributions by employers (funded plans)	754	129	123	60	1,066
Benefit payments (funded plans)[d]	(1,269)	(1,124)	(81)	(178)	(2,652)
Acquisitions	–	–	–	7	7
Remeasurements[f]	315	(139)	25	33	234
Fair value of plan assets at 31 December[g]	31,223	7,510	1,874	1,531	42,138
Surplus (deficit) at 31 December	2,249	(3,133)	(4,766)	(558)	(6,208)
Represented by					
Asset recognized	2,516	66	25	40	2,647
Liability recognized	(267)	(3,199)	(4,791)	(598)	(8,855)
	2,249	(3,133)	(4,766)	(558)	(6,208)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	2,506	49	(254)	(187)	2,114
Unfunded	(257)	(3,182)	(4,512)	(371)	(8,322)
	2,249	(3,133)	(4,766)	(558)	(6,208)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(28,717)	(7,461)	(2,128)	(1,718)	(40,024)
Unfunded	(257)	(3,182)	(4,512)	(371)	(8,322)
	(28,974)	(10,643)	(6,640)	(2,089)	(48,346)

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-retirement benefit plans are included in the benefit obligation.
[b] Past service costs have arisen from restructuring programmes and represent a combination of credits as a result of the curtailment in the pension arrangements of a number of employees mostly in the US and Trinidad and charges for special termination benefits representing the increased liability arising as a result of early retirements mostly in the UK and Eurozone.
[c] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.
[d] The benefit payments amount shown above comprises $3,128 million benefits and $57 million settlements, plus $62 million of plan expenses incurred in the administration of the benefit.
[e] The benefit obligation for the US is made up of $8,061 million for pension liabilities and $2,582 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,151 million for pension liabilities in Germany which is largely unfunded.
[f] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.
[g] The fair value of plan assets includes borrowings related to the LDI programme as described on page 142.

23. Pensions and other post-retirement benefits – continued

					$ million
					2014
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit (loss) before interest and taxation					
Current service cost[a]	494	356	72	87	1,009
Past service cost[b]	–	(33)	20	1	(12)
Settlement[c]	–	(66)	–	–	(66)
Operating charge relating to defined benefit plans	494	257	92	88	931
Payments to defined contribution plans	30	214	11	54	309
Total operating charge	524	471	103	142	1,240
Interest income on plan assets[a]	(1,425)	(317)	(70)	(80)	(1,892)
Interest on plan liabilities	1,378	458	255	115	2,206
Other finance expense	(47)	141	185	35	314
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	1,269	768	119	31	2,187
Change in financial assumptions underlying the present value of the plan liabilities	(3,188)	(1,004)	(1,845)	(350)	(6,387)
Change in demographic assumptions underlying the present value of the plan liabilities	42	(264)	(20)	(9)	(251)
Experience gains and losses arising on the plan liabilities	(41)	13	(86)	(25)	(139)
Remeasurements recognized in other comprehensive income	(1,918)	(487)	(1,832)	(353)	(4,590)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	30,552	11,002	7,536	2,443	51,533
Exchange adjustments	(1,993)	–	(1,040)	(256)	(3,289)
Operating charge relating to defined benefit plans	494	257	92	88	931
Interest cost	1,378	458	255	115	2,206
Contributions by plan participants[d]	39	–	4	7	50
Benefit payments (funded plans)[e]	(1,231)	(865)	(83)	(119)	(2,298)
Benefit payments (unfunded plans)[e]	(10)	(238)	(370)	(24)	(642)
Acquisitions	–	6	–	–	6
Disposals	–	–	(18)	–	(18)
Remeasurements	3,187	1,255	1,951	384	6,777
Benefit obligation at 31 December[a f]	32,416	11,875	8,327	2,638	55,256
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	31,516	7,778	2,015	1,822	43,131
Exchange adjustments	(1,958)	–	(257)	(161)	(2,376)
Interest income on plan assets[a g]	1,425	317	70	80	1,892
Contributions by plan participants[d]	39	–	4	7	50
Contributions by employers (funded plans)	713	354	110	75	1,252
Benefit payments (funded plans)[e]	(1,231)	(865)	(83)	(119)	(2,298)
Acquisitions	–	3	–	–	3
Disposals	–	–	(5)	–	(5)
Remeasurements[g]	1,269	768	119	31	2,187
Fair value of plan assets at 31 December	31,773	8,355	1,973	1,735	43,836
Surplus (deficit) at 31 December	(643)	(3,520)	(6,354)	(903)	(11,420)
Represented by					
Asset recognized	15	–	3	13	31
Liability recognized	(658)	(3,520)	(6,357)	(916)	(11,451)
	(643)	(3,520)	(6,354)	(903)	(11,420)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	(310)	(19)	(663)	(384)	(1,376)
Unfunded	(333)	(3,501)	(5,691)	(519)	(10,044)
	(643)	(3,520)	(6,354)	(903)	(11,420)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(32,083)	(8,374)	(2,636)	(2,119)	(45,212)
Unfunded	(333)	(3,501)	(5,691)	(519)	(10,044)
	(32,416)	(11,875)	(8,327)	(2,638)	(55,256)

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-retirement benefit plans are included in the benefit obligation.
[b] Past service costs in the US include a credit of $21 million as the result of a curtailment in the pension arrangement of a number of employees following a business reorganization and a credit of $12 million reflecting a plan amendment to a medical plan. A charge of $21 million for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes mostly in the Eurozone.
[c] Settlements represent a gain of $66 million arising from an offer to a group of plan members in the US to settle annuity liabilities with lump sum payments.
[d] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.
[e] The benefit payments amount shown above comprises $2,621 million benefits and $257 million settlements, plus $62 million of plan expenses incurred in the administration of the benefit.
[f] The benefit obligation for the US is made up of $9,033 million for pension liabilities and $2,842 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $5,220 million for pension liabilities in Germany which is largely unfunded.
[g] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.

23. Pensions and other post-retirement benefits – continued

	UK	US	Eurozone	Other	$ million 2013 Total
Analysis of the amount charged to profit (loss) before interest and taxation					
Current service cost[a]	497	407	81	96	1,081
Past service cost	(22)	(49)	26	1	(44)
Settlement	–	–	–	(1)	(1)
Operating charge relating to defined benefit plans	475	358	107	96	1,036
Payments to defined contribution plans	24	223	9	44	300
Total operating charge	499	581	116	140	1,336
Interest income on plan assets[a]	(1,139)	(240)	(63)	(67)	(1,509)
Interest on plan liabilities	1,223	406	254	106	1,989
Other finance expense	84	166	191	39	480
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	2,671	730	15	99	3,515
Change in financial assumptions underlying the present value of the plan liabilities	68	1,160	62	213	1,503
Change in demographic assumptions underlying the present value of the plan liabilities	–	14	–	(65)	(51)
Experience gains and losses arising on the plan liabilities	43	(249)	2	1	(203)
Remeasurements recognized in other comprehensive income	2,782	1,655	79	248	4,764

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-retirement benefit plans are included in the benefit obligation.

At 31 December 2015, reimbursement balances due from or to other companies in respect of pensions amounted to $377 million reimbursement assets (2014 $426 million) and $13 million reimbursement liabilities (2014 $16 million). These balances are not included as part of the pension surpluses and deficits, but are reflected within other receivables and other payables in the group balance sheet.

Sensitivity analysis

The discount rate, inflation, salary growth and the mortality assumptions all have a significant effect on the amounts reported. A one-percentage point change, in isolation, in certain assumptions as at 31 December 2015 for the group's plans would have had the effects shown in the table below. The effects shown for the expense in 2016 comprise the total of current service cost and net finance income or expense.

	$ million One percentage point Increase	 Decrease
Discount rate[a]		
Effect on pension and other post-retirement benefit expense in 2016	**(416)**	**387**
Effect on pension and other post-retirement benefit obligation at 31 December 2015	**(6,897)**	**8,911**
Inflation rate[b]		
Effect on pension and other post-retirement benefit expense in 2016	**408**	**(312)**
Effect on pension and other post-retirement benefit obligation at 31 December 2015	**6,996**	**(5,523)**
Salary growth		
Effect on pension and other post-retirement benefit expense in 2016	**112**	**(99)**
Effect on pension and other post-retirement benefit obligation at 31 December 2015	**1,135**	**(1,004)**

[a] The amounts presented reflect that the discount rate is used to determine the asset interest income as well as the interest cost on the obligation.
[b] The amounts presented reflect the total impact of an inflation rate change on the assumptions for rate of increase in salaries, pensions in payment and deferred pensions.

One additional year of longevity in the mortality assumptions would increase the 2016 pension and other post-retirement benefit expense by $60 million and the pension and other post-retirement benefit obligation at 31 December 2015 by $1,329 million.

Estimated future benefit payments and the weighted average duration of defined benefit obligations

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2025 and the weighted average duration of the defined benefit obligations at 31 December 2015 are as follows:

Estimated future benefit payments	UK	US	Eurozone	Other	$ million Total
2016	**1,061**	**966**	**363**	**120**	**2,510**
2017	**1,098**	**838**	**345**	**117**	**2,398**
2018	**1,150**	**846**	**337**	**121**	**2,454**
2019	**1,188**	**839**	**327**	**125**	**2,479**
2020	**1,210**	**834**	**319**	**127**	**2,490**
2021-2025	**6,575**	**3,966**	**1,517**	**667**	**12,725**
					years
Weighted average duration	**18.2**	**9.4**	**14.0**	**14.0**	

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24. Cash and cash equivalents

		$ million
	2015	2014
Cash	**4,653**	5,112
Term bank deposits	**16,749**	18,392
Cash equivalents	**4,987**	6,259
	26,389	29,763

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; term deposits of three months or less with banks and similar institutions; money market funds and commercial paper. The carrying amounts of cash and term bank deposits approximate their fair values. Substantially all of the other cash equivalents are categorized within level 1 of the fair value hierarchy.

Cash and cash equivalents at 31 December 2015 includes $2,439 million (2014 $2,264 million) that is restricted. The restricted cash balances include amounts required to cover initial margin on trading exchanges and certain cash balances which are subject to exchange controls.

The group holds $4,329 million (2014 $3,852 million) of cash and cash equivalents outside the UK and it is not expected that any significant tax will arise on repatriation.

25. Finance debt

						$ million
			2015			2014
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**6,898**	**45,567**	**52,465**	6,831	45,240	52,071
Net obligations under finance leases	**46**	**657**	**703**	46	737	783
	6,944	**46,224**	**53,168**	6,877	45,977	52,854

The main elements of current borrowings are the current portion of long-term borrowings that is due to be repaid in the next 12 months of $5,942 million (2014 $6,343 million) and issued commercial paper of $869 million (2014 $444 million). Finance debt does not include accrued interest, which is reported within other payables.

At 31 December 2015, $122 million (2014 $137 million) of finance debt was secured by the pledging of assets. The remainder of finance debt was unsecured.

The following table shows the weighted average interest rates achieved through a combination of borrowings and derivative financial instruments entered into to manage interest rate and currency exposures.

			Fixed rate debt		**Floating rate debt**	**Total**
	Weighted average interest rate %	**Weighted average time for which rate is fixed Years**	**Amount $ million**	**Weighted average interest rate %**	**Amount $ million**	**Amount $ million**
						2015
US dollar	**3**	**4**	**10,442**	**1**	**40,623**	**51,065**
Other currencies	**6**	**17**	**826**	**1**	**1,277**	**2,103**
			11,268		**41,900**	**53,168**
						2014
US dollar	3	3	14,285	1	36,275	50,560
Other currencies	6	19	871	1	1,423	2,294
			15,156		37,698	52,854

The floating rate debt denominated in other currencies represents euro debt not swapped to US dollars, which is naturally hedged with respect to foreign currency risk by holding equivalent euro cash and cash equivalent amounts.

Fair values

The estimated fair value of finance debt is shown in the table below together with the carrying amount as reflected in the balance sheet.

Long-term borrowings in the table below include the portion of debt that matures in the 12 months from 31 December 2015, whereas in the balance sheet the amount is reported within current finance debt.

The carrying amount of the group's short-term borrowings, comprising mainly commercial paper, approximates their fair value. The fair values of the majority of the group's long-term borrowings are determined using quoted prices in active markets, and so fall within level 1 of the fair value hierarchy. Where quoted prices are not available, quoted prices for similar instruments in active markets are used and such measurements are therefore categorized in level 2 of the fair value hierarchy. The fair value of the group's finance lease obligations is estimated using discounted cash flow analyses based on the group's current incremental borrowing rates for similar types and maturities of borrowing and are consequently categorized in level 2 of the fair value hierarchy.

				$ million
		2015		2014
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**956**	**956**	487	487
Long-term borrowings	**51,404**	**51,509**	51,995	51,584
Net obligations under finance leases	**1,178**	**703**	1,343	783
Total finance debt	**53,538**	**53,168**	53,825	52,854

26. Capital disclosures and analysis of changes in net debt

The group defines capital as total equity. We maintain our financial framework to support the pursuit of value growth for shareholders, while ensuring a secure financial base.

The group monitors capital on the basis of the net debt ratio, that is, the ratio of net debt to net debt plus equity. Net debt is calculated as gross finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is applied, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. BP believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total. The net debt ratio enables investors to see how significant net debt is relative to equity from shareholders. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. All components of equity are included in the denominator of the calculation.

We aim to maintain the net debt ratio, with some flexibility, at around 20%. We expect the net debt ratio to be above 20% while oil prices remain weak. At 31 December 2015, the net debt ratio was 21.6% (2014 16.7%).

		$ million
At 31 December	**2015**	2014
Gross debt	**53,168**	52,854
Less: fair value asset (liability) of hedges related to finance debt[a]	**(379)**	445
	53,547	52,409
Less: cash and cash equivalents	**26,389**	29,763
Net debt	**27,158**	22,646
Equity	**98,387**	112,642
Net debt ratio	**21.6%**	16.7%

[a] Derivative financial instruments entered into for the purpose of managing interest rate and foreign currency exchange risk associated with net debt with a fair value liability position of $1,617 million (2014 liability of $774 million) are not included in the calculation of net debt shown above as hedge accounting was not applied for these instruments.

An analysis of changes in net debt is provided below.

						$ million
		2015				2014
Movement in net debt	**Finance debt[a]**	**Cash and cash equivalents**	**Net debt**	Finance debt[a]	Cash and cash equivalents	Net debt
At 1 January	**(52,409)**	**29,763**	**(22,646)**	(47,715)	22,520	(25,195)
Exchange adjustments	**1,065**	**(672)**	**393**	1,160	(671)	489
Net cash flow	**(2,220)**	**(2,702)**	**(4,922)**	(5,419)	7,914	2,495
Other movements	**17**	**–**	**17**	(435)	–	(435)
At 31 December	**(53,547)**	**26,389**	**(27,158)**	(52,409)	29,763	(22,646)

[a] Including the fair value of associated derivative financial instruments for which hedge accounting is applied.

27. Operating leases

The cost recognized in relation to minimum lease payments for the year was $6,008 million (2014 $6,324 million and 2013 $5,961 million).

The future minimum lease payments at 31 December 2015, before deducting related rental income from operating sub-leases of $166 million (2014 $234 million), are shown in the table below. This does not include future contingent rentals. Where the lease rentals are dependent on a variable factor, the future minimum lease payments are based on the factor as at inception of the lease.

		$ million
Future minimum lease payments	**2015**	2014
Payable within		
1 year	**4,144**	5,401
2 to 5 years	**7,743**	9,916
Thereafter	**3,535**	3,468
	15,422	18,785

In the case of an operating lease entered into by BP as the operator of a joint operation, the amounts included in the totals disclosed represent the net operating lease expense and net future minimum lease payments. These net amounts are after deducting amounts reimbursed, or to be reimbursed, by joint operators, whether the joint operators have co-signed the lease or not. Where BP is not the operator of a joint operation, BP's share of the lease expense and future minimum lease payments is included in the amounts shown, whether BP has co-signed the lease or not.

Typical durations of operating leases are up to forty years for leases of land and buildings, up to fifteen years for leases of ships and commercial vehicles and up to ten years for leases of plant and machinery.

The group has entered into a number of structured operating leases for ships and in most cases the lease rental payments vary with market interest rates. The variable portion of the lease payments above or below the amount based on the market interest rate prevailing at inception of the lease is treated as contingent rental expense. The group also routinely enters into bareboat charters, time-charters and voyage-charters for ships on standard industry terms.

The most significant items of plant and machinery hired under operating leases are drilling rigs used in the Upstream segment. At 31 December 2015, the future minimum lease payments relating to drilling rigs amounted to $4,783 million (2014 $8,180 million).

Commercial vehicles hired under operating leases are primarily railcars. Retail service station sites and office accommodation are the main items in the land and buildings category.

The terms and conditions of these operating leases do not impose any significant financial restrictions on the group. Some of the leases of ships and buildings allow for renewals at BP's option, and some of the group's operating leases contain escalation clauses.

28. Financial instruments and financial risk factors

The accounting classification of each category of financial instruments, and their carrying amounts, are set out below.

$ million

At 31 December 2015	Note	Loans and receivables	Available-for-sale financial assets	Held-to-maturity investments	At fair value through profit or loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
Financial assets								
Other investments – equity shares	**17**	**–**	**397**	**–**	**–**	**–**	**–**	**397**
– other	**17**	**–**	**219**	**–**	**605**	**–**	**–**	**824**
Loans		**801**	**–**	**–**	**–**	**–**	**–**	**801**
Trade and other receivables	**19**	**22,214**	**–**	**–**	**–**	**–**	**–**	**22,214**
Derivative financial instruments	**29**	**–**	**–**	**–**	**7,700**	**951**	**–**	**8,651**
Cash and cash equivalents	**24**	**21,402**	**2,859**	**2,128**	**–**	**–**	**–**	**26,389**
Financial liabilities								
Trade and other payables	**21**	**–**	**–**	**–**	**–**	**–**	**(32,094)**	**(32,094)**
Derivative financial instruments	**29**	**–**	**–**	**–**	**(6,139)**	**(1,383)**	**–**	**(7,522)**
Accruals		**–**	**–**	**–**	**–**	**–**	**(7,151)**	**(7,151)**
Finance debt	**25**	**–**	**–**	**–**	**–**	**–**	**(53,168)**	**(53,168)**
		44,417	**3,475**	**2,128**	**2,166**	**(432)**	**(92,413)**	**(40,659)**
At 31 December 2014								
Financial assets								
Other investments – equity shares	17	–	420	–	–	–	–	420
– other	17	–	538	–	599	–	–	1,137
Loans		992	–	–	–	–	–	992
Trade and other receivables	19	30,551	–	–	–	–	–	30,551
Derivative financial instruments	29	–	–	–	8,511	1,096	–	9,607
Cash and cash equivalents	24	23,504	2,989	3,270	–	–	–	29,763
Financial liabilities								
Trade and other payables	21	–	–	–	–	–	(40,327)	(40,327)
Derivative financial instruments	29	–	–	–	(6,100)	(788)	–	(6,888)
Accruals		–	–	–	–	–	(7,963)	(7,963)
Finance debt	25	–	–	–	–	–	(52,854)	(52,854)
		55,047	3,947	3,270	3,010	308	(101,144)	(35,562)

The fair value of finance debt is shown in Note 25. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

Financial risk factors

The group is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments including market risks relating to commodity prices, foreign currency exchange rates and interest rates; credit risk; and liquidity risk.

The group financial risk committee (GFRC) advises the group chief financial officer (CFO) who oversees the management of these risks. The GFRC is chaired by the CFO and consists of a group of senior managers including the group treasurer and the heads of the group finance, tax and the integrated supply and trading functions. The purpose of the committee is to advise on financial risks and the appropriate financial risk governance framework for the group. The committee provides assurance to the CFO and the group chief executive (GCE), and via the GCE to the board, that the group's financial risk-taking activity is governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with group policies and group risk appetite.

The group's trading activities in the oil, natural gas, LNG and power markets are managed within the integrated supply and trading function, while the activities in the financial markets are managed by the treasury function, working under the compliance and control structure of the integrated supply and trading function. All derivative activity is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control.

The integrated supply and trading function maintains formal governance processes that provide oversight of market risk, credit risk and operational risk associated with trading activity. A policy and risk committee monitors and validates limits and risk exposures, reviews incidents and validates risk-related policies, methodologies and procedures. A commitments committee approves value-at-risk delegations, the trading of new products, instruments and strategies and material commitments.

In addition, the integrated supply and trading function undertakes derivative activity for risk management purposes under a control framework as described more fully below.

(a) Market risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of a business. The primary commodity price risks that the group is exposed to include oil, natural gas and power prices that could adversely affect the value of the group's financial assets, liabilities or expected future cash flows. The group enters into derivatives in a well-established entrepreneurial trading operation. In addition, the group has developed a control framework aimed at managing the volatility inherent in certain of its natural business exposures. In accordance with the control framework the group enters into various transactions using derivatives for risk management purposes.

The major components of market risk are commodity price risk, foreign currency exchange risk and interest rate risk, each of which is discussed below.

28. Financial instruments and financial risk factors – continued

(i) Commodity price risk
The group's integrated supply and trading function uses conventional financial and commodity instruments and physical cargoes and pipeline positions available in the related commodity markets. Oil and natural gas swaps, options and futures are used to mitigate price risk. Power trading is undertaken using a combination of over-the-counter forward contracts and other derivative contracts, including options and futures. This activity is on both a standalone basis and in conjunction with gas derivatives in relation to gas-generated power margin. In addition, NGLs are traded around certain US inventory locations using over-the-counter forward contracts in conjunction with over-the-counter swaps, options and physical inventories.

The group measures market risk exposure arising from its trading positions in liquid periods using value-at-risk techniques. These techniques make a statistical assessment of the market risk arising from possible future changes in market prices over a one-day holding period. The value-at-risk measure is supplemented by stress testing. Trading activity occurring in liquid periods is subject to value-at-risk limits for each trading activity and for this trading activity in total. The board has delegated a limit of $100 million value at risk in support of this trading activity. Alternative measures are used to monitor exposures which are outside liquid periods and which cannot be actively risk-managed.

(ii) Foreign currency exchange risk
Where the group enters into foreign currency exchange contracts for entrepreneurial trading purposes the activity is controlled using trading value-at-risk techniques as explained above.

Since BP has global operations, fluctuations in foreign currency exchange rates can have a significant effect on the group's reported results. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates and translation differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the group's reported results. The main underlying economic currency of the group's cash flows is the US dollar. This is because BP's major product, oil, is priced internationally in US dollars. BP's foreign currency exchange management policy is to limit economic and material transactional exposures arising from currency movements against the US dollar. The group co-ordinates the handling of foreign currency exchange risks centrally, by netting off naturally-occurring opposite exposures wherever possible, and then managing any material residual foreign currency exchange risks.

The group manages these exposures by constantly reviewing the foreign currency economic value at risk and aims to manage such risk to keep the 12-month foreign currency value at risk below $400 million. At no point over the past three years did the value at risk exceed the maximum risk limit. The most significant exposures relate to capital expenditure commitments and other UK, Eurozone and Australian operational requirements, for which hedging programmes are in place and hedge accounting is applied as outlined in Note 1.

For highly probable forecast capital expenditures the group locks in the US dollar cost of non-US dollar supplies by using currency forwards and futures. The main exposures are sterling, euro, Australian dollar and South Korean won. At 31 December 2015 the most significant open contracts in place were for $627 million sterling (2014 $321 million sterling).

For other UK, Eurozone and Australian operational requirements the group uses cylinders (purchased call and sold put options) to manage the estimated exposures on a 12-month rolling basis. At 31 December 2015, the open positions relating to cylinders consisted of receive sterling, pay US dollar cylinders for $2,479 million (2014 $2,787 million); receive euro, pay US dollar cylinders for $560 million (2014 $867 million); receive Australian dollar, pay US dollar cylinders for $312 million (2014 $418 million).

In addition, most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2015, the total foreign currency net borrowings not swapped into US dollars amounted to $826 million (2014 $871 million).

(iii) Interest rate risk
Where the group enters into money market contracts for entrepreneurial trading purposes the activity is controlled using value-at-risk techniques as described above.

BP is also exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments, principally finance debt. While the group issues debt in a variety of currencies based on market opportunities, it uses derivatives to swap the debt to a floating rate exposure, mainly to US dollar floating, but in certain defined circumstances maintains a US dollar fixed rate exposure for a proportion of debt. The proportion of floating rate debt net of interest rate swaps at 31 December 2015 was 79% of total finance debt outstanding (2014 71%). The weighted average interest rate on finance debt at 31 December 2015 was 2% (2014 2%) and the weighted average maturity of fixed rate debt was five years (2014 four years).

The group's earnings are sensitive to changes in interest rates on the floating rate element of the group's finance debt. If the interest rates applicable to floating rate instruments were to have increased by one percentage point on 1 January 2016, it is estimated that the group's finance costs for 2016 would increase by approximately $419 million (2014 $377 million increase).

(b) Credit risk
Credit risk is the risk that a customer or counterparty to a financial instrument will fail to perform or fail to pay amounts due causing financial loss to the group and arises from cash and cash equivalents, derivative financial instruments and deposits with financial institutions and principally from credit exposures to customers relating to outstanding receivables. Credit exposure also exists in relation to guarantees issued by group companies under which the outstanding exposure incremental to that recognized on the balance sheet at 31 December 2015 was $35 million (2014 $83 million) in respect of liabilities of joint ventures and associates and $163 million (2014 $244 million) in respect of liabilities of other third parties.

The group has a credit policy, approved by the CFO that is designed to ensure that consistent processes are in place throughout the group to measure and control credit risk. Credit risk is considered as part of the risk-reward balance of doing business. On entering into any business contract the extent to which the arrangement exposes the group to credit risk is considered. Key requirements of the policy include segregation of credit approval authorities from any sales, marketing or trading teams authorized to incur credit risk; the establishment of credit systems and processes to ensure that all counterparty exposure is rated and that all counterparty exposure and limits can be monitored and reported; and the timely identification and reporting of any non-approved credit exposures and credit losses. While each segment is responsible for its own credit risk management and reporting consistent with group policy, the treasury function holds group-wide credit risk authority and oversight responsibility for exposure to banks and financial institutions.

The maximum credit exposure associated with financial assets is equal to the carrying amount. The group does not aim to remove credit risk entirely but expects to experience a certain level of credit losses. As at 31 December 2015, the group had in place credit enhancements designed to mitigate approximately $10.9 billion of credit risk (2014 $10.8 billion). Reports are regularly prepared and presented to the GFRC that cover the group's overall credit exposure and expected loss trends, exposure by segment, and overall quality of the portfolio.

28. Financial instruments and financial risk factors – continued

Management information used to monitor credit risk indicates that 81% (2014 82%) of total unmitigated credit exposure relates to counterparties of investment-grade credit quality.

Trade and other receivables at 31 December	2015	2014
		$ million
Neither impaired nor past due	**21,064**	28,519
Impaired (net of provision)	**22**	37
Not impaired and past due in the following periods		
within 30 days	**414**	841
31 to 60 days	**75**	249
61 to 90 days	**118**	178
over 90 days	**521**	727
	22,214	30,551

Movements in the impairment provision for trade receivables are shown in Note 20.

Financial instruments subject to offsetting, enforceable master netting arrangements and similar agreements

The following table shows the amounts recognized for financial assets and liabilities which are subject to offsetting arrangements on a gross basis, and the amounts offset in the balance sheet.

Amounts which cannot be offset under IFRS, but which could be settled net under the terms of master netting agreements if certain conditions arise, and collateral received or pledged, are also presented in the table to show the total net exposure of the group.

				Related amounts not set off in the balance sheet		$ million
At 31 December 2015	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the balance sheet	Master netting arrangements	Cash collateral (received) pledged	Net amount
Derivative assets	**10,206**	**(1,859)**	**8,347**	**(1,109)**	**(297)**	**6,941**
Derivative liabilities	**(9,280)**	**1,859**	**(7,421)**	**1,109**	**–**	**(6,312)**
Trade receivables	**7,091**	**(3,689)**	**3,402**	**(322)**	**(161)**	**2,919**
Trade payables	**(5,720)**	**3,689**	**(2,031)**	**322**	**–**	**(1,709)**
At 31 December 2014						
Derivative assets	11,515	(2,383)	9,132	(1,164)	(458)	7,510
Derivative liabilities	(8,971)	2,383	(6,588)	1,164	–	(5,424)
Trade receivables	10,502	(6,080)	4,422	(485)	(145)	3,792
Trade payables	(9,062)	6,080	(2,982)	485	–	(2,497)

(c) Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the group's business activities may not be available. The group's liquidity is managed centrally with operating units forecasting their cash and currency requirements to the central treasury function. Unless restricted by local regulations, generally subsidiaries pool their cash surpluses to treasury, which will then arrange to fund other subsidiaries' requirements, or invest any net surplus in the market or arrange for necessary external borrowings, while managing the group's overall net currency positions.

Standard & Poor's Ratings long-term credit rating for BP is A negative (stable outlook) and Moody's Investors Service rating is A2 (rating under review from positive).

During 2015, $8 billion of long-term taxable bonds were issued with terms ranging from 1 to 11 years. Commercial paper is issued at competitive rates to meet short-term borrowing requirements as and when needed.

As a further liquidity measure, the group continues to maintain suitable levels of cash and cash equivalents, amounting to $26.4 billion at 31 December 2015 (2014 $29.8 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2015, the group had substantial amounts of undrawn borrowing facilities available, consisting of $7,375 million of standby facilities, of which $6,975 million is available to draw and repay until the first half of 2018, and $400 million is available to draw and repay until April 2017. These facilities were renegotiated during 2015 with 26 international banks, and borrowings under them would be at pre-agreed rates.

The group also has committed letter of credit (LC) facilities totalling $6,850 million with a number of banks, allowing LCs to be issued for a maximum two-year duration. There were also uncommitted secured LC facilities in place at 31 December 2015 for $2,410 million, which are secured against inventories or receivables when utilized. The facilities only terminate by either party giving a stipulated termination notice to the other.

28. Financial instruments and financial risk factors – continued

The amounts shown for finance debt in the table below include future minimum lease payments with respect to finance leases. The table also shows the timing of cash outflows relating to trade and other payables and accruals.

								$ million
				2015				2014
	Trade and other payables	**Accruals**	**Finance debt**	**Interest relating to finance debt**	Trade and other payables	Accruals	Finance debt	Interest relating to finance debt
Within one year	**29,743**	**6,261**	**6,944**	**928**	37,342	7,102	6,877	892
1 to 2 years	**971**	**380**	**5,796**	**812**	708	493	6,311	776
2 to 3 years	**1,231**	**138**	**6,208**	**704**	757	119	5,652	672
3 to 4 years	**56**	**98**	**6,103**	**592**	1,446	76	5,226	578
4 to 5 years	**17**	**74**	**6,354**	**478**	23	41	6,056	479
5 to 10 years	**38**	**167**	**17,651**	**1,068**	24	95	19,504	1,111
Over 10 years	**38**	**33**	**4,112**	**402**	27	37	3,228	521
	32,094	**7,151**	**53,168**	**4,984**	40,327	7,963	52,854	5,029

The group manages liquidity risk associated with derivative contracts, other than derivative hedging instruments, based on the expected maturities of both derivative assets and liabilities as indicated in Note 29. Management does not currently anticipate any cash flows that could be of a significantly different amount, or could occur earlier than the expected maturity analysis provided.

The table below shows the timing of cash outflows for derivative financial instruments entered into for the purpose of managing interest rate and foreign currency exchange risk associated with net debt, whether or not hedge accounting is applied, based upon contractual payment dates. The amounts reflect the gross settlement amount where the pay leg of a derivative will be settled separately from the receive leg, as in the case of cross-currency swaps hedging non-US dollar finance debt. The swaps are with high investment-grade counterparties and therefore the settlement-day risk exposure is considered to be negligible. Not shown in the table are the gross settlement amounts (inflows) for the receive leg of derivatives that are settled separately from the pay leg, which amount to $15,706 million at 31 December 2015 (2014 $14,615 million) to be received on the same day as the related cash outflows. For further information on our derivative financial instruments, see Note 29.

		$ million
	2015	2014
Within one year	**2,959**	293
1 to 2 years	**2,685**	2,959
2 to 3 years	**1,505**	2,690
3 to 4 years	**1,700**	1,505
4 to 5 years	**1,678**	1,700
5 to 10 years	**5,500**	5,764
Over 10 years	**2,739**	1,325
	18,766	16,236

29. Derivative financial instruments

In the normal course of business the group enters into derivative financial instruments (derivatives) to manage its normal business exposures in relation to commodity prices, foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt, consistent with risk management policies and objectives. An outline of the group's financial risks and the objectives and policies pursued in relation to those risks is set out in Note 28. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts.

For information on significant estimates and judgements made in relation to the application of hedge accounting and the valuation of derivatives see Derivative financial instruments within Note 1.

The fair values of derivative financial instruments at 31 December are set out below.

Exchange traded derivatives are valued using closing prices provided by the exchange as at the balance sheet date. These derivatives are categorized within level 1 of the fair value hierarchy. Over-the-counter (OTC) financial swaps and physical commodity sale and purchase contracts are generally valued using readily available information in the public markets and quotations provided by brokers and price index developers. These quotes are corroborated with market data and are categorized within level 2 of the fair value hierarchy.

In certain less liquid markets, or for longer-term contracts, forward prices are not as readily available. In these circumstances, OTC financial swaps and physical commodity sale and purchase contracts are valued using internally developed methodologies that consider historical relationships between various commodities, and that result in management's best estimate of fair value. These contracts are categorized within level 3 of the fair value hierarchy.

29. Derivative financial instruments – continued

Financial OTC and physical commodity options are valued using industry standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and contractual prices for the underlying instruments, as well as other relevant economic factors. The degree to which these inputs are observable in the forward markets determines whether the option is categorized within level 2 or level 3 of the fair value hierarchy.

				$ million
		2015		2014
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**144**	**(1,811)**	122	(902)
Oil price derivatives	**2,390**	**(1,257)**	3,133	(1,976)
Natural gas price derivatives	**3,942**	**(2,536)**	3,859	(2,518)
Power price derivatives	**920**	**(434)**	922	(404)
Other derivatives	**292**	**–**	389	–
	7,688	**(6,038)**	8,425	(5,800)
Embedded derivatives				
Commodity price contracts	**12**	**(101)**	86	(300)
	12	**(101)**	86	(300)
Cash flow hedges				
Currency forwards, futures and cylinders	**9**	**(71)**	1	(161)
Cross-currency interest rate swaps	**–**	**(147)**	–	(97)
	9	**(218)**	1	(258)
Fair value hedges				
Currency forwards, futures and swaps	**33**	**(1,108)**	78	(518)
Interest rate swaps	**909**	**(57)**	1,017	(12)
	942	**(1,165)**	1,095	(530)
	8,651	**(7,522)**	9,607	(6,888)
Of which – current	**4,242**	**(3,239)**	5,165	(3,689)
– non-current	**4,409**	**(4,283)**	4,442	(3,199)

Derivatives held for trading

The group maintains active trading positions in a variety of derivatives. The contracts may be entered into for risk management purposes, to satisfy supply requirements or for entrepreneurial trading. Certain contracts are classified as held for trading, regardless of their original business objective, and are recognized at fair value with changes in fair value recognized in the income statement. Trading activities are undertaken by using a range of contract types in combination to create incremental gains by arbitraging prices between markets, locations and time periods. The net of these exposures is monitored using market value-at-risk techniques as described in Note 28.

The following tables show further information on the fair value of derivatives and other financial instruments held for trading purposes.

Derivative assets held for trading have the following fair values and maturities.

							$ million
							2015
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**132**	**10**	**1**	**1**	**–**	**–**	**144**
Oil price derivatives	**1,729**	**432**	**130**	**58**	**37**	**4**	**2,390**
Natural gas price derivatives	**1,707**	**639**	**390**	**283**	**202**	**721**	**3,942**
Power price derivatives	**459**	**164**	**103**	**79**	**47**	**68**	**920**
Other derivatives	**182**	**110**	**–**	**–**	**–**	**–**	**292**
	4,209	**1,355**	**624**	**421**	**286**	**793**	**7,688**

							$ million
							2014
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	120	–	2	–	–	–	122
Oil price derivatives	2,434	416	185	63	31	4	3,133
Natural gas price derivatives	1,991	644	261	202	160	601	3,859
Power price derivatives	488	203	87	50	39	55	922
Other derivatives	70	97	161	61	–	–	389
	5,103	1,360	696	376	230	660	8,425

At both 31 December 2015 and 2014 the group had contingent consideration receivable in respect of the disposal of the Texas City refinery. The sale agreement contained an embedded derivative – the whole agreement has, consequently, been designated at fair value through profit or loss and shown within other derivatives held for trading, and falls within level 3 of the fair value hierarchy. The valuation depends on refinery throughput and future margins.

29. Derivative financial instruments – continued

Derivative liabilities held for trading have the following fair values and maturities.

							$ million
							2015
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**(499)**	**(2)**	**(2)**	**(347)**	**(79)**	**(882)**	**(1,811)**
Oil price derivatives	**(1,053)**	**(163)**	**(26)**	**(10)**	**(2)**	**(3)**	**(1,257)**
Natural gas price derivatives	**(1,037)**	**(382)**	**(210)**	**(146)**	**(162)**	**(599)**	**(2,536)**
Power price derivatives	**(246)**	**(70)**	**(31)**	**(34)**	**(17)**	**(36)**	**(434)**
	(2,835)	**(617)**	**(269)**	**(537)**	**(260)**	**(1,520)**	**(6,038)**

							$ million
							2014
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(69)	(180)	(1)	(1)	(192)	(459)	(902)
Oil price derivatives	(1,714)	(186)	(61)	(8)	(6)	(1)	(1,976)
Natural gas price derivatives	(1,310)	(292)	(144)	(117)	(99)	(556)	(2,518)
Power price derivatives	(217)	(127)	(39)	(10)	(4)	(7)	(404)
	(3,310)	(785)	(245)	(136)	(301)	(1,023)	(5,800)

The following table shows the fair value of derivative assets and derivative liabilities held for trading, analysed by maturity period and by methodology of fair value estimation. This information is presented on a gross basis, that is, before netting by counterparty.

							$ million
							2015
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Fair value of derivative assets							
Level 1	**109**	**–**	**–**	**–**	**–**	**–**	**109**
Level 2	**4,946**	**1,137**	**402**	**213**	**68**	**50**	**6,816**
Level 3	**684**	**449**	**271**	**240**	**230**	**748**	**2,622**
	5,739	**1,586**	**673**	**453**	**298**	**798**	**9,547**
Less: netting by counterparty	**(1,530)**	**(231)**	**(49)**	**(32)**	**(12)**	**(5)**	**(1,859)**
	4,209	**1,355**	**624**	**421**	**286**	**793**	**7,688**
Fair value of derivative liabilities							
Level 1	**(104)**	**–**	**–**	**–**	**–**	**–**	**(104)**
Level 2	**(4,083)**	**(700)**	**(177)**	**(423)**	**(124)**	**(889)**	**(6,396)**
Level 3	**(178)**	**(148)**	**(141)**	**(146)**	**(148)**	**(636)**	**(1,397)**
	(4,365)	**(848)**	**(318)**	**(569)**	**(272)**	**(1,525)**	**(7,897)**
Less: netting by counterparty	**1,530**	**231**	**49**	**32**	**12**	**5**	**1,859**
	(2,835)	**(617)**	**(269)**	**(537)**	**(260)**	**(1,520)**	**(6,038)**
Net fair value	**1,374**	**738**	**355**	**(116)**	**26**	**(727)**	**1,650**

							$ million
							2014
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of derivative assets							
Level 1	170	–	–	–	–	–	170
Level 2	6,388	1,353	354	130	71	20	8,316
Level 3	483	374	409	255	159	642	2,322
	7,041	1,727	763	385	230	662	10,808
Less: netting by counterparty	(1,938)	(367)	(67)	(9)	–	(2)	(2,383)
	5,103	1,360	696	376	230	660	8,425
Fair value of derivative liabilities							
Level 1	(37)	–	–	–	–	–	(37)
Level 2	(4,905)	(1,017)	(197)	(45)	(202)	(488)	(6,854)
Level 3	(306)	(135)	(115)	(100)	(99)	(537)	(1,292)
	(5,248)	(1,152)	(312)	(145)	(301)	(1,025)	(8,183)
Less: netting by counterparty	1,938	367	67	9	–	2	2,383
	(3,310)	(785)	(245)	(136)	(301)	(1,023)	(5,800)
Net fair value	1,793	575	451	240	(71)	(363)	2,625

29. Derivative financial instruments – continued

Level 3 derivatives

The following table shows the changes during the year in the net fair value of derivatives held for trading purposes within level 3 of the fair value hierarchy.

					$ million
	Oil price	**Natural gas price**	**Power price**	**Other**	**Total**
Net fair value of contracts at 1 January 2015	**246**	**181**	**214**	**389**	**1,030**
Gains (losses) recognized in the income statement	**(24)**	**272**	**79**	**92**	**419**
Inception fair value of new contracts	**126**	**14**	**87**	**–**	**227**
Settlements	**(20)**	**(40)**	**(72)**	**(189)**	**(321)**
Transfers out of level 3	**–**	**(107)**	**(23)**	**–**	**(130)**
Net fair value of contracts at 31 December 2015	**328**	**320**	**285**	**292**	**1,225**

					$ million
	Oil price	Natural gas price	Power price	Other	Total
Net fair value of contracts at 1 January 2014	(18)	313	86	475	856
Gains recognized in the income statement	270	133	79	94	576
Inception fair value of new contracts	80	19	62	–	161
Settlements	(86)	(56)	(13)	(180)	(335)
Transfers out of level 3	–	(228)	–	–	(228)
Net fair value of contracts at 31 December 2014	246	181	214	389	1,030

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2015 was a $293 million gain (2014 $456 million gain related to derivatives still held at 31 December 2014).

Derivative gains and losses

Gains and losses relating to derivative contracts are included within sales and other operating revenues and within purchases in the income statement depending upon the nature of the activity and type of contract involved. The contract types treated in this way include futures, options, swaps and certain forward sales and forward purchases contracts, and relate to both currency and commodity trading activities. Gains or losses arise on contracts entered into for risk management purposes, optimization activity and entrepreneurial trading. They also arise on certain contracts that are for normal procurement or sales activity for the group but that are required to be fair valued under accounting standards. Also included within sales and other operating revenues are gains and losses on inventory held for trading purposes. The total amount relating to all these items (excluding gains and losses on realized physical derivative contracts that have been reflected gross in the income statement within sales and purchases) was a net gain of $5,508 million (2014 $6,154 million net gain and 2013 $587 million net gain). This number does not include gains and losses on realized physical derivative contracts that have been reflected gross in the income statement within sales and purchases or the change in value of transportation and storage contracts which are not recognized under IFRS, but does include the associated financially settled contracts. The net amount for actual gains and losses relating to derivative contracts and all related items therefore differs significantly from the amount disclosed above.

Embedded derivatives

The group has embedded derivatives relating to certain natural gas contracts. The fair value gain on commodity price embedded derivatives included within distribution and administration expenses was $120 million (2014 gain of $430 million, 2013 gain of $459 million).

Cash flow hedges

At 31 December 2015, the group held currency forwards, futures contracts and cylinders and cross-currency interest rate swaps that were being used to hedge the foreign currency risk of highly probable forecast transactions and floating rate finance debt. Note 28 outlines the group's approach to foreign currency exchange risk management. For cash flow hedges the group only claims hedge accounting for the intrinsic value on the currency with any fair value attributable to time value taken immediately to the income statement. The amounts remaining in equity at 31 December 2015 in relation to these cash flow hedges consist of deferred losses of $55 million maturing in 2016, deferred losses of $15 million maturing in 2017 and deferred losses of $3 million maturing in 2018 and beyond.

Two of the contracts to acquire an 18.5% interest in Rosneft, which completed in March 2013, were designated as hedging instruments in a cash flow hedge. A cumulative charge of $651 million has been recognized in other comprehensive income, of which a charge of $2,061 million arose in 2013. This loss will only be reclassified to the income statement if the investment in Rosneft is either sold or impaired.

Fair value hedges

At 31 December 2015, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk on fixed rate debt issued by the group. The loss on the hedging derivative instruments recognized in the income statement in 2015 was $788 million (2014 $14 million loss and 2013 $1,240 million loss) offset by a gain on the fair value of the finance debt of $833 million (2014 $8 million gain and 2013 $1,228 million gain).

The interest rate and cross-currency interest rate swaps mature within one to eleven years, and have the same maturity terms as the debt that they are hedging. They are used to convert sterling, euro, Swiss franc, Australian dollar, Canadian dollar, Norwegian Krone and Hong Kong dollar denominated fixed rate borrowings into floating rate debt. Note 28 outlines the group's approach to interest rate and foreign currency exchange risk management.

30. Called-up share capital

The allotted, called up and fully paid share capital at 31 December was as follows:

	2015		2014		2013	
Issued	**Shares thousand**	**$ million**	Shares thousand	$ million	Shares thousand	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,005,961**	**5,002**	20,426,632	5,108	20,959,159	5,240
Issue of new shares for the scrip dividend programme	**102,810**	**26**	165,644	41	202,124	51
Issue of new shares for employee share-based payment plans[b]	**–**	**–**	25,598	6	18,203	5
Repurchase of ordinary share capital[c]	**–**	**–**	(611,913)	(153)	(752,854)	(188)
At 31 December	**20,108,771**	**5,028**	20,005,961	5,002	20,426,632	5,108
		5,049		5,023		5,129

[a] The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.

[b] Consideration received relating to the issue of new shares for employee share-based payment plans amounted to $207 million in 2014 and $116 million in 2013.

[c] There were no shares repurchased in 2015 (2014 shares were repurchased for a total consideration of $4,796 million, including transaction costs of $26 million and 2013 shares were repurchased for a total consideration of $5,493 million, including transaction costs of $30 million). All shares purchased were for cancellation.

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

Treasury shares[a]

	2015		2014		2013	
	Shares thousand	**Nominal value $ million**	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,811,297**	**453**	1,833,544	458	1,864,510	466
Purchases for settlement of employee share plans	**51,142**	**13**	49,559	12	38,766	9
Shares re-issued for employee share-based payment plans	**(106,112)**	**(27)**	(71,806)	(17)	(69,732)	(17)
At 31 December	**1,756,327**	**439**	1,811,297	453	1,833,544	458
Of which – shares held in treasury by BP	**1,727,763**	**432**	1,771,103	443	1,787,939	447
– shares held in ESOP trusts	**18,453**	**4**	34,169	9	32,748	8
– shares held by BP[b]	**10,111**	**3**	6,025	1	12,857	3

[a] See Note 31 for definition of treasury shares.

[b] Held by the group in the form of ADSs to meet the requirements of employee share-based payment plans in the US.

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury by BP during the year, representing 8.9% (2014 8.8% and 2013 8.7%) of the called-up ordinary share capital of the company.

During 2015, the movement in shares held in treasury by BP represented less than 0.2% (2014 less than 0.1% and 2013 less than 0.2%) of the ordinary share capital of the company.

31. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2015	**5,023**	**10,260**	**1,413**	**27,206**	**43,902**
Profit (loss) for the year	–	–	–	–	–
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)[a]	–	–	–	–	–
Available-for-sale investments (including recycling)	–	–	–	–	–
Cash flow hedges (including recycling)	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax[a]	–	–	–	–	–
Other	–	–	–	–	–
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	**26**	**(26)**	–	–	–
Share-based payments, net of tax[b]	–	–	–	–	–
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	–
Transactions involving non-controlling interests	–	–	–	–	–
At 31 December 2015	**5,049**	**10,234**	**1,413**	**27,206**	**43,902**

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2014	5,129	10,061	1,260	27,206	43,656
Profit (loss) for the year	–	–	–	–	–
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)[a]	–	–	–	–	–
Cash flow hedges (including recycling)	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax[a]	–	–	–	–	–
Other	–	–	–	–	–
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	41	(41)	–	–	–
Repurchases of ordinary share capital	(153)	–	153	–	–
Share-based payments, net of tax[b]	6	240	–	–	246
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	–
Transactions involving non-controlling interests	–	–	–	–	–
At 31 December 2014	5,023	10,260	1,413	27,206	43,902

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2013	5,261	9,974	1,072	27,206	43,513
Profit (loss) for the year	–	–	–	–	–
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)	–	–	–	–	–
Available-for-sale investments (including recycling)	–	–	–	–	–
Cash flow hedges (including recycling)	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax	–	–	–	–	–
Other	–	–	–	–	–
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	51	(51)	–	–	–
Repurchases of ordinary share capital	(188)	–	188	–	–
Share-based payments, net of tax[b]	5	138	–	–	143
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	–
Transactions involving non-controlling interests	–	–	–	–	–
At 31 December 2013	5,129	10,061	1,260	27,206	43,656

[a] Principally affected by a weakening of the Russian rouble compared to the US dollar.
[b] Includes new share issues and movements in treasury shares where these relate to employee share-based payment plans.

$ million

Treasury shares	**Foreign currency translation reserve**	**Available-for-sale investments**	**Cash flow hedges**	**Total fair value reserves**	**Profit and loss account**	**BP shareholders' equity**	**Non-controlling interests**	**Total equity**
(20,719)	**(3,409)**	**1**	**(898)**	**(897)**	**92,564**	**111,441**	**1,201**	**112,642**
–	**–**	**–**	**–**	**–**	**(6,482)**	**(6,482)**	**82**	**(6,400)**
–	**(3,858)**	**–**	**–**	**–**	**–**	**(3,858)**	**(41)**	**(3,899)**
–	**–**	**1**	**–**	**1**	**–**	**1**	**–**	**1**
–	**–**	**–**	**73**	**73**	**–**	**73**	**–**	**73**
–	**–**	**–**	**–**	**–**	**(814)**	**(814)**	**–**	**(814)**
–	**–**	**–**	**–**	**–**	**80**	**80**	**–**	**80**
–	**–**	**–**	**–**	**–**	**2,742**	**2,742**	**–**	**2,742**
–	**–**	**–**	**–**	**–**	**(1)**	**(1)**	**–**	**(1)**
–	**(3,858)**	**1**	**73**	**74**	**(4,475)**	**(8,259)**	**41**	**(8,218)**
–	**–**	**–**	**–**	**–**	**(6,659)**	**(6,659)**	**(91)**	**(6,750)**
755	**–**	**–**	**–**	**–**	**(99)**	**656**	**–**	**656**
–	**–**	**–**	**–**	**–**	**40**	**40**	**–**	**40**
–	**–**	**–**	**–**	**–**	**(3)**	**(3)**	**20**	**17**
(19,964)	**(7,267)**	**2**	**(825)**	**(823)**	**81,368**	**97,216**	**1,171**	**98,387**

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(20,971)	3,525	–	(695)	(695)	103,787	129,302	1,105	130,407
–	–	–	–	–	3,780	3,780	223	4,003
–	(6,934)	1	–	1	–	(6,933)	(32)	(6,965)
–	–	–	(203)	(203)	–	(203)	–	(203)
–	–	–	–	–	(2,584)	(2,584)	–	(2,584)
–	–	–	–	–	289	289	–	289
–	–	–	–	–	(3,256)	(3,256)	–	(3,256)
–	–	–	–	–	4	4	–	4
–	(6,934)	1	(203)	(202)	(1,767)	(8,903)	191	(8,712)
–	–	–	–	–	(5,850)	(5,850)	(255)	(6,105)
–	–	–	–	–	(3,366)	(3,366)	–	(3,366)
252	–	–	–	–	(313)	185	–	185
–	–	–	–	–	73	73	–	73
–	–	–	–	–	–	–	160	160
(20,719)	(3,409)	1	(898)	(897)	92,564	111,441	1,201	112,642

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(21,054)	5,128	685	1,090	1,775	89,184	118,546	1,206	119,752
–	–	–	–	–	23,451	23,451	307	23,758
–	(1,603)	–	–	–	–	(1,603)	(15)	(1,618)
–	–	(685)	–	(685)	–	(685)	–	(685)
–	–	–	(1,785)	(1,785)	–	(1,785)	–	(1,785)
–	–	–	–	–	(24)	(24)	–	(24)
–	–	–	–	–	(25)	(25)	–	(25)
–	–	–	–	–	3,243	3,243	–	3,243
–	–	–	–	–	2	2	–	2
–	(1,603)	(685)	(1,785)	(2,470)	26,647	22,574	292	22,866
–	–	–	–	–	(5,441)	(5,441)	(469)	(5,910)
–	–	–	–	–	(6,923)	(6,923)	–	(6,923)
83	–	–	–	–	247	473	–	473
–	–	–	–	–	73	73	–	73
–	–	–	–	–	–	–	76	76
(20,971)	3,525	–	(695)	(695)	103,787	129,302	1,105	130,407

31. Capital and reserves – continued

Share capital
The balance on the share capital account represents the aggregate nominal value of all ordinary and preference shares in issue, including treasury shares.

Share premium account
The balance on the share premium account represents the amounts received in excess of the nominal value of the ordinary and preference shares.

Capital redemption reserve
The balance on the capital redemption reserve represents the aggregate nominal value of all the ordinary shares repurchased and cancelled.

Merger reserve
The balance on the merger reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares.

Treasury shares
Treasury shares represent BP shares repurchased and available for specific and limited purposes.

For accounting purposes shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans are treated in the same manner as treasury shares and are therefore included in the financial statements as treasury shares. The ESOPs are funded by the group and have waived their rights to dividends in respect of such shares held for future awards. Until such time as the shares held by the ESOPs vest unconditionally to employees, the amount paid for those shares is shown as a reduction in shareholders' equity. Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

Foreign currency translation reserve
The foreign currency translation reserve records exchange differences arising from the translation of the financial statements of foreign operations. Upon disposal of foreign operations, the related accumulated exchange differences are recycled to the income statement.

Available-for-sale investments
This reserve records the changes in fair value of available-for-sale investments except for impairment losses, foreign exchange gains or losses, or changes arising from revised estimates of future cash flows. On disposal or impairment of the investments, the cumulative changes in fair value are recycled to the income statement.

Cash flow hedges
This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. For further information see Note 1 - Derivative financial instruments and hedging activities.

Profit and loss account
The balance held on this reserve is the accumulated retained profits of the group.

31. Capital and reserves – continued

The pre-tax amounts of each component of other comprehensive income, and the related amounts of tax, are shown in the table below.

			$ million
			2015
	Pre-tax	**Tax**	**Net of tax**
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	**(4,096)**	**197**	**(3,899)**
Available-for-sale investments (including recycling)	**1**	**–**	**1**
Cash flow hedges (including recycling)	**93**	**(20)**	**73**
Share of items relating to equity-accounted entities, net of tax	**(814)**	**–**	**(814)**
Other	**–**	**80**	**80**
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	**4,139**	**(1,397)**	**2,742**
Share of items relating to equity-accounted entities, net of tax	**(1)**	**–**	**(1)**
Other comprehensive income	**(678)**	**(1,140)**	**(1,818)**

			$ million
			2014
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	(6,787)	(178)	(6,965)
Cash flow hedges (including recycling)	(239)	36	(203)
Share of items relating to equity-accounted entities, net of tax	(2,584)	–	(2,584)
Other	–	289	289
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	(4,590)	1,334	(3,256)
Share of items relating to equity-accounted entities, net of tax	4	–	4
Other comprehensive income	(14,196)	1,481	(12,715)

			$ million
			2013
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	(1,586)	(32)	(1,618)
Available-for-sale investments (including recycling)	(695)	10	(685)
Cash flow hedges (including recycling)	(1,979)	194	(1,785)
Share of items relating to equity-accounted entities, net of tax	(24)	–	(24)
Other	–	(25)	(25)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	4,764	(1,521)	3,243
Share of items relating to equity-accounted entities, net of tax	2	–	2
Other comprehensive income	482	(1,374)	(892)

32. Contingent liabilities

Contingent liabilities related to the Gulf of Mexico oil spill

Details of contingent liabilities related to the Gulf of Mexico oil spill are set out in Note 2.

Contingent liabilities not related to the Gulf of Mexico oil spill

There were contingent liabilities at 31 December 2015 in respect of guarantees and indemnities entered into as part of the ordinary course of the group's business. No material losses are likely to arise from such contingent liabilities. Further information is included in Note 28.

In the normal course of the group's business, legal proceedings are pending or may be brought against BP group entities arising out of current and past operations, including matters related to commercial disputes, product liability, antitrust, commodities trading, premises-liability claims, consumer protection, general environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. BP believes that the impact of these legal proceedings on the group's results of operations, liquidity or financial position will not be material.

With respect to lead pigment in paint in particular, Atlantic Richfield, a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property. Although it is not possible to predict the outcome of the legal proceedings, Atlantic Richfield believes it has valid defences that render the incurrence of a liability remote; however, the amounts claimed and the costs of implementing the remedies sought in the various cases could be substantial. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. Atlantic Richfield intends to defend such actions vigorously.

The group files tax returns in many jurisdictions throughout the world. Various tax authorities are currently examining the group's tax returns. Tax returns contain matters that could be subject to differing interpretations of applicable tax laws and regulations and the resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete. While it is difficult to predict the ultimate outcome in some cases, the group does not anticipate that there will be any material impact upon the group's results of operations, financial position or liquidity.

32. Contingent liabilities – continued

The group is subject to numerous national and local environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the group to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the group or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, service stations, terminals and waste disposal sites. In addition, the group may have obligations relating to prior asset sales or closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the group's accounting policies. While the amounts of future costs that are not provided for could be significant and could be material to the group's results of operations in the period in which they are recognized, it is not possible to estimate the amounts involved. BP does not expect these costs to have a material effect on the group's financial position or liquidity.

If oil and natural gas production facilities and pipelines are sold to third parties and the subsequent owner is unable to meet their decommissioning obligations it is possible that, in certain circumstances, BP could be partially or wholly responsible for decommissioning. Furthermore, as described in Provisions, contingencies and reimbursement assets within Note 1, decommissioning provisions associated with downstream and petrochemical facilities are not generally recognized as the potential obligations cannot be measured given their indeterminate settlement dates.

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. Typically, losses will therefore be borne as they arise rather than being spread over time through insurance premiums. Some risks are insured with third parties and reinsured through group insurance companies. The position is reviewed periodically.

33. Remuneration of senior management and non-executive directors

Remuneration of directors

			$ million
	2015	2014	2013
Total for all directors			
Emoluments	**10**	14	16
Amounts awarded under incentive schemes[a]	**14**	10	2
Total	**24**	24	18

[a] Excludes amounts relating to past directors.

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus cash bonuses awarded for the year.

Pension contributions

During 2015 one executive director participated in a non-contributory defined benefit pension plan established for UK employees by a separate trust fund to which contributions are made by BP based on actuarial advice. One executive director participated in 2015 in a US defined benefit pension plan and retirement savings plans established for US employees.

Further information

Full details of individual directors' remuneration are given in the Directors' remuneration report on page 76.

Remuneration of directors and senior management

			$ million
	2015	2014	2013
Total for senior management and non-executive directors			
Short-term employee benefits	**33**	34	36
Pensions and other post-retirement benefits	**4**	3	3
Share-based payments	**36**	34	43
Total	**73**	71	82

Senior management comprises members of the executive team, see pages 60-61 for further information.

Short-term employee benefits

These amounts comprise fees and benefits paid to the non-executive chairman and non-executive directors, as well as salary, benefits and cash bonuses for senior management. Deferred annual bonus awards, to be settled in shares, are included in share-based payments. There was no compensation for loss of office included in Short-term employee benefits in 2015 (2014 $1.5 million and 2013 $3 million).

Pensions and other post-retirement benefits

The amounts represent the estimated cost to the group of providing pensions and other post-retirement benefits to senior management in respect of the current year of service measured in accordance with IAS 19 'Employee Benefits'.

Share-based payments

This is the cost to the group of senior management's participation in share-based payment plans, as measured by the fair value of options and shares granted, accounted for in accordance with IFRS 2 'Share-based Payments'.

34. Employee costs and numbers

Employee costs	2015	2014	2013
			$ million
Wages and salaries[a]	**9,556**	10,710	10,161
Social security costs	**879**	983	958
Share-based payments[b]	**833**	689	719
Pension and other post-retirement benefit costs	**1,660**	1,554	1,816
	12,928	13,936	13,654

Average number of employees[c]	2015 US	2015 Non-US	2015 Total	2014 US	2014 Non-US	2014 Total	2013 US	2013 Non-US	2013 Total
Upstream	**7,900**	**15,100**	**23,000**	9,100	15,600	24,700	9,400	15,100	24,500
Downstream[d e]	**7,800**	**38,200**	**46,000**	8,200	39,900	48,100	9,300	39,800	49,100
Other businesses and corporate[e f g]	**1,700**	**11,900**	**13,600**	1,800	10,100	11,900	2,000	9,000	11,000
	17,400	**65,200**	**82,600**	19,100	65,600	84,700	20,700	63,900	84,600

[a] Includes termination payments of $857 million (2014 $527 million and 2013 $212 million).
[b] The group provides certain employees with shares and share options as part of their remuneration packages. The majority of these share-based payment arrangements are equity-settled.
[c] Reported to the nearest 100.
[d] Includes 15,000 (2014 14,200 and 2013 14,100) service station staff.
[e] Around 2,000 employees from the global business services organization were reallocated from Downstream to Other businesses and corporate during 2015.
[f] Includes 5,600 (2014 5,100 and 2013 4,300) agricultural, operational and seasonal workers in Brazil.
[g] Includes employees of the Gulf Coast Restoration Organization.

35. Auditor's remuneration

Fees – Ernst & Young	2015	2014	2013
			$ million
The audit of the company annual accounts[a]	**27**	27	26
The audit of accounts of subsidiaries of the company	**13**	13	13
Total audit	**40**	40	39
Audit-related assurance services[b]	**7**	7	8
Total audit and audit-related assurance services	**47**	47	47
Taxation compliance services	**1**	1	1
Taxation advisory services	**–**	1	1
Services relating to corporate finance transactions	**1**	1	2
Total non-audit and other assurance services	**1**	2	1
Total non-audit or non-audit-related assurance services	**3**	5	5
Services relating to BP pension plans[c]	**1**	1	1
	51	53	53

[a] Fees in respect of the audit of the accounts of BP p.l.c. including the group's consolidated financial statements.
[b] Includes interim reviews and reporting on internal financial controls and non-statutory audit services.
[c] The pension plan services include tax compliance service of $0.4 million (2014 $0.4 million and 2013 $0.2 million)

2015 includes $2 million of additional fees for 2014 and 2014 includes $2 million of additional fees for 2013. Auditors' remuneration is included in the income statement within distribution and administration expenses.

The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the Committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young compared with that of other potential service providers. These services are for a fixed term.

Under SEC regulations, the remuneration of the auditor of $51 million (2014 $53 million and 2013 $53 million) is required to be presented as follows: audit $40 million (2014 $40 million and 2013 $39 million); other audit-related $7 million (2014 $7 million and 2013 $8 million); tax $1 million (2014 $2 million and 2013 $2 million); and all other fees $3 million (2014 $4 million and 2013 $4 million).

36. Subsidiaries, joint arrangements and associates

The more important subsidiaries and associates of the group at 31 December 2015 and the group percentage of ordinary share capital (to nearest whole number) are set out below. There are no individually significant joint arrangements. Those held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of undertakings of the group is included in Note 15 in the parent company financial statements of BP p.l.c. which are filed with the Registrar of Companies in the UK, along with the group's annual report.

Subsidiaries	%	Country of incorporation	Principal activities
International			
*BP Corporate Holdings	100	England & Wales	Investment holding
BP Exploration Operating Company	100	England & Wales	Exploration and production
*BP Global Investments	100	England & Wales	Investment holding
*BP International	100	England & Wales	Integrated oil operations
BP Oil International	100	England & Wales	Integrated oil operations
*Burmah Castrol	100	Scotland	Lubricants
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
Angola			
BP Exploration (Angola)	100	England & Wales	Exploration and production
Australia			
BP Australia Capital Markets	100	Australia	Finance
BP Finance Australia	100	Australia	Finance
Azerbaijan			
BP Exploration (Caspian Sea)	100	England & Wales	Exploration and production
BP Exploration (Azerbaijan)	100	England & Wales	Exploration and production
Canada			
*BP Holdings Canada	100	England & Wales	Investment holding
Egypt			
BP Exploration (Delta)	100	England & Wales	Exploration and production
Germany			
BP Europa SE	100	England & Wales	Refining and marketing
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
Trinidad & Tobago			
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England & Wales	Finance
US			
*BP Holdings North America	100	England & Wales	Investment holding
Atlantic Richfield Company	100	US	Exploration and production, refining and marketing pipelines and petrochemicals
BP America	100	US	
BP America Production Company	100	US	
BP Company North America	100	US	
BP Corporation North America	100	US	
BP Exploration & Production	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
Standard Oil Company	100	US	
BP Capital Markets America	100	US	Finance

Associates	%	Country of incorporation	Principal activities
Russia			
Rosneft	20	Russia	Integrated oil operations

37. Condensed consolidating information on certain US subsidiaries

BP p.l.c. fully and unconditionally guarantees the payment obligations of its 100%-owned subsidiary BP Exploration (Alaska) Inc. under the BP Prudhoe Bay Royalty Trust. The following financial information for BP p.l.c., BP Exploration (Alaska) Inc. and all other subsidiaries on a condensed consolidating basis is intended to provide investors with meaningful and comparable financial information about BP p.l.c. and its subsidiary issuers of registered securities and is provided pursuant to Rule 3-10 of Regulation S-X in lieu of the separate financial statements of each subsidiary issuer of public debt securities. Non-current assets for BP p.l.c. includes investments in subsidiaries recorded under the equity method for the purposes of the condensed consolidating financial information. Equity-accounted income of subsidiaries is the group's share of profit related to such investments. The eliminations and reclassifications column includes the necessary amounts to eliminate the intercompany balances and transactions between BP p.l.c., BP Exploration (Alaska) Inc. and other subsidiaries. The financial information presented in the following tables for BP Exploration (Alaska) Inc. incorporates subsidiaries of BP Exploration (Alaska) Inc. using the equity method of accounting and excludes the BP group's midstream operations in Alaska that are reported through different legal entities and that are included within the 'other subsidiaries' column in these tables. BP p.l.c. also fully and unconditionally guarantees securities issued by BP Capital Markets p.l.c. and BP Capital Markets America Inc. These companies are 100%-owned finance subsidiaries of BP p.l.c.

Income statement

					$ million
For the year ended 31 December					2015
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	3,438	–	222,881	(3,425)	222,894
Earnings from joint ventures – after interest and tax	–	–	(28)	–	(28)
Earnings from associates – after interest and tax	–	–	1,839	–	1,839
Equity-accounted income of subsidiaries – after interest and tax	–	(5,404)	–	5,404	–
Interest and other income	29	185	671	(274)	611
Gains on sale of businesses and fixed assets	–	31	666	(31)	666
Total revenues and other income	3,467	(5,188)	226,029	1,674	225,982
Purchases	1,432	–	166,783	(3,425)	164,790
Production and manufacturing expenses	1,360	–	35,680	–	37,040
Production and similar taxes	140	–	896	–	1,036
Depreciation, depletion and amortization	569	–	14,650	–	15,219
Impairment and losses on sale of businesses and fixed assets	215	–	1,694	–	1,909
Exploration expense	–	–	2,353	–	2,353
Distribution and administration expenses	56	1,125	10,449	(77)	11,553
Profit (loss) before interest and taxation	(305)	(6,313)	(6,476)	5,176	(7,918)
Finance costs	35	36	1,473	(197)	1,347
Net finance (income) expense relating to pensions and other post-retirement benefits	–	20	286	–	306
Profit (loss) before taxation	(340)	(6,369)	(8,235)	5,373	(9,571)
Taxation	(146)	82	(3,107)	–	(3,171)
Profit (loss) for the year	(194)	(6,451)	(5,128)	5,373	(6,400)
Attributable to					
BP shareholders	(194)	(6,451)	(5,210)	5,373	(6,482)
Non-controlling interests	–	–	82	–	82
	(194)	(6,451)	(5,128)	5,373	(6,400)

Statement of comprehensive income

					$ million
For the year ended 31 December					2015
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	(194)	(6,451)	(5,128)	5,373	(6,400)
Other comprehensive income	–	1,863	(3,681)	–	(1,818)
Equity-accounted other comprehensive income of subsidiaries	–	(3,640)	–	3,640	–
Total comprehensive income	(194)	(8,228)	(8,809)	9,013	(8,218)
Attributable to					
BP shareholders	(194)	(8,228)	(8,850)	9,013	(8,259)
Non-controlling interests	–	–	41	–	41
	(194)	(8,228)	(8,809)	9,013	(8,218)

37. Condensed consolidating information on certain US subsidiaries – continued

Income statement continued

For the year ended 31 December	Issuer: BP Exploration (Alaska) Inc.	Guarantor: BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					2014
Sales and other operating revenues	6,227	–	353,529	(6,188)	353,568
Earnings from joint ventures – after interest and tax	–	–	570	–	570
Earnings from associates – after interest and tax	–	–	2,802	–	2,802
Equity-accounted income of subsidiaries – after interest and tax	–	4,531	–	(4,531)	–
Interest and other income	2	193	910	(262)	843
Gains on sale of businesses and fixed assets	19	–	876	–	895
Total revenues and other income	6,248	4,724	358,687	(10,981)	358,678
Purchases	2,375	–	285,720	(6,188)	281,907
Production and manufacturing expenses	1,779	–	25,596	–	27,375
Production and similar taxes	554	–	2,404	–	2,958
Depreciation, depletion and amortization	545	–	14,618	–	15,163
Impairment and losses on sale of businesses and fixed assets	153	–	8,812	–	8,965
Exploration expense	–	–	3,632	–	3,632
Distribution and administration expenses	48	929	11,364	(75)	12,266
Profit (loss) before interest and taxation	794	3,795	6,541	(4,718)	6,412
Finance costs	57	23	1,255	(187)	1,148
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(50)	364	–	314
Profit (loss) before taxation	737	3,822	4,922	(4,531)	4,950
Taxation	279	42	626	–	947
Profit (loss) for the year	458	3,780	4,296	(4,531)	4,003
Attributable to					
BP shareholders	458	3,780	4,073	(4,531)	3,780
Non-controlling interests	–	–	223	–	223
	458	3,780	4,296	(4,531)	4,003

Statement of comprehensive income continued

For the year ended 31 December	Issuer: BP Exploration (Alaska) Inc.	Guarantor: BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					2014
Profit (loss) for the year	458	3,780	4,296	(4,531)	4,003
Other comprehensive income	–	(1,840)	(10,875)	–	(12,715)
Equity-accounted other comprehensive income of subsidiaries	–	(10,843)	–	10,843	–
Total comprehensive income	458	(8,903)	(6,579)	6,312	(8,712)
Attributable to					
BP shareholders	458	(8,903)	(6,770)	6,312	(8,903)
Non-controlling interests	–	–	191	–	191
	458	(8,903)	(6,579)	6,312	(8,712)

37. Condensed consolidating information on certain US subsidiaries – continued

Income statement continued

$ million

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					2013
Sales and other operating revenues	5,397	–	379,136	(5,397)	379,136
Earnings from joint ventures – after interest and tax	–	–	447	–	447
Earnings from associates – after interest and tax	–	–	2,742	–	2,742
Equity-accounted income of subsidiaries – after interest and tax	–	24,693	–	(24,693)	–
Interest and other income	7	118	841	(189)	777
Gains on sale of businesses and fixed assets	–	–	13,115	–	13,115
Total revenues and other income	5,404	24,811	396,281	(30,279)	396,217
Purchases	861	–	302,887	(5,397)	298,351
Production and manufacturing expenses	1,473	–	26,054	–	27,527
Production and similar taxes	1,010	–	6,037	–	7,047
Depreciation, depletion and amortization	616	–	12,894	–	13,510
Impairment and losses on sale of businesses and fixed assets	(68)	–	2,029	–	1,961
Exploration expense	–	–	3,441	–	3,441
Distribution and administration expenses	108	1,234	11,269	–	12,611
Profit (loss) before interest and taxation	1,404	23,577	31,670	(24,882)	31,769
Finance costs	42	43	1,172	(189)	1,068
Net finance (income) expense relating to pensions and other post-retirement benefits	–	81	399	–	480
Profit (loss) before taxation	1,362	23,453	30,099	(24,693)	30,221
Taxation	522	2	5,939	–	6,463
Profit (loss) for the year	840	23,451	24,160	(24,693)	23,758
Attributable to					
BP shareholders	840	23,451	23,853	(24,693)	23,451
Non-controlling interests	–	–	307	–	307
	840	23,451	24,160	(24,693)	23,758

Statement of comprehensive income continued

$ million

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					2013
Profit (loss) for the year	840	23,451	24,160	(24,693)	23,758
Other comprehensive income	–	2,819	(3,711)	–	(892)
Equity-accounted other comprehensive income of subsidiaries	–	(3,696)	–	3,696	–
Total comprehensive income	840	22,574	20,449	(20,997)	22,866
Attributable to					
BP shareholders	840	22,574	20,157	(20,997)	22,574
Non-controlling interests	–	–	292	–	292
	840	22,574	20,449	(20,997)	22,866

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37. Condensed consolidating information on certain US subsidiaries – continued

Balance sheet

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2015 BP group
Non-current assets					
Property, plant and equipment	8,306	–	121,452	–	129,758
Goodwill	–	–	11,627	–	11,627
Intangible assets	539	–	18,121	–	18,660
Investments in joint ventures	–	–	8,412	–	8,412
Investments in associates	–	2	9,420	–	9,422
Other investments	–	–	1,002	–	1,002
Subsidiaries – equity-accounted basis	–	128,234	–	(128,234)	–
Fixed assets	8,845	128,236	170,034	(128,234)	178,881
Loans	3	–	7,245	(6,719)	529
Trade and other receivables	–	–	2,216	–	2,216
Derivative financial instruments	–	–	4,409	–	4,409
Prepayments	4	–	999	–	1,003
Deferred tax assets	–	–	1,545	–	1,545
Defined benefit pension plan surpluses	–	2,516	131	–	2,647
	8,852	130,752	186,579	(134,953)	191,230
Current assets					
Loans	–	–	272	–	272
Inventories	246	–	13,896	–	14,142
Trade and other receivables	9,718	1,062	22,393	(10,850)	22,323
Derivative financial instruments	–	–	4,242	–	4,242
Prepayments	7	–	1,831	–	1,838
Current tax receivable	–	–	599	–	599
Other investments	–	–	219	–	219
Cash and cash equivalents	–	–	26,389	–	26,389
	9,971	1,062	69,841	(10,850)	70,024
Assets classified as held for sale	–	–	578	–	578
	9,971	1,062	70,419	(10,850)	70,602
Total assets	18,823	131,814	256,998	(145,803)	261,832
Current liabilities					
Trade and other payables	961	127	41,711	(10,850)	31,949
Derivative financial instruments	–	–	3,239	–	3,239
Accruals	116	81	6,064	–	6,261
Finance debt	–	–	6,944	–	6,944
Current tax payable	(21)	4	1,097	–	1,080
Provisions	1	–	5,153	–	5,154
	1,057	212	64,208	(10,850)	54,627
Liabilities directly associated with assets classified as held for sale	–	–	97	–	97
	1,057	212	64,305	(10,850)	54,724
Non-current liabilities					
Other payables	8	6,708	2,913	(6,719)	2,910
Derivative financial instruments	–	–	4,283	–	4,283
Accruals	–	33	857	–	890
Finance debt	–	–	46,224	–	46,224
Deferred tax liabilities	1,238	877	7,484	–	9,599
Provisions	2,326	–	33,634	–	35,960
Defined benefit pension plan and other post-retirement benefit plan deficits	–	227	8,628	–	8,855
	3,572	7,845	104,023	(6,719)	108,721
Total liabilities	4,629	8,057	168,328	(17,569)	163,445
Net assets	14,194	123,757	88,670	(128,234)	98,387
Equity					
BP shareholders' equity	14,194	123,757	87,499	(128,234)	97,216
Non-controlling interests	–	–	1,171	–	1,171
	14,194	123,757	88,670	(128,234)	98,387

37. Condensed consolidating information on certain US subsidiaries – continued

Balance sheet continued

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.[a]	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					2014
Non-current assets					
Property, plant and equipment	7,787	–	122,905	–	130,692
Goodwill	–	–	11,868	–	11,868
Intangible assets	473	–	20,434	–	20,907
Investments in joint ventures	–	–	8,753	–	8,753
Investments in associates	–	2	10,401	–	10,403
Other investments	–	–	1,228	–	1,228
Subsidiaries – equity-accounted basis	–	138,863	–	(138,863)	–
Fixed assets	8,260	138,865	175,589	(138,863)	183,851
Loans	7	–	5,238	(4,586)	659
Trade and other receivables	–	–	4,787	–	4,787
Derivative financial instruments	–	–	4,442	–	4,442
Prepayments	10	–	954	–	964
Deferred tax assets	–	–	2,309	–	2,309
Defined benefit pension plan surpluses	–	15	16	–	31
	8,277	138,880	193,335	(143,449)	197,043
Current assets					
Loans	–	–	333	–	333
Inventories	338	–	18,035	–	18,373
Trade and other receivables	10,323	7,159	33,463	(19,907)	31,038
Derivative financial instruments	–	–	5,165	–	5,165
Prepayments	31	–	1,393	–	1,424
Current tax receivable	–	–	837	–	837
Other investments	–	–	329	–	329
Cash and cash equivalents	–	31	29,732	–	29,763
	10,692	7,190	89,287	(19,907)	87,262
Total assets	18,969	146,070	282,622	(163,356)	284,305
Current liabilities					
Trade and other payables	905	168	56,644	(17,599)	40,118
Derivative financial instruments	–	–	3,689	–	3,689
Accruals	134	391	6,577	–	7,102
Finance debt	–	–	6,877	–	6,877
Current tax payable	328	–	1,683	–	2,011
Provisions	1	–	3,817	–	3,818
	1,368	559	79,287	(17,599)	63,615
Non-current liabilities					
Other payables	16	6,871	3,594	(6,894)	3,587
Derivative financial instruments	–	–	3,199	–	3,199
Accruals	–	90	771	–	861
Finance debt	–	–	45,977	–	45,977
Deferred tax liabilities	1,232	–	12,661	–	13,893
Provisions	1,975	–	27,105	–	29,080
Defined benefit pension plan and other post-retirement benefit plan deficits	–	599	10,852	–	11,451
	3,223	7,560	104,159	(6,894)	108,048
Total liabilities	4,591	8,119	183,446	(24,493)	171,663
Net assets	14,378	137,951	99,176	(138,863)	112,642
Equity					
BP shareholders' equity	14,378	137,951	97,975	(138,863)	111,441
Non-controlling interests	–	–	1,201	–	1,201
	14,378	137,951	99,176	(138,863)	112,642

[a] For 2014 BP p.l.c. comparative balances there has been a reclassification from amounts due within one year to amounts due after one year.

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37. Condensed consolidating information on certain US subsidiaries – continued

Cash flow statement

For the year ended 31 December	Issuer: BP Exploration (Alaska) Inc.	Guarantor: BP p.l.c.	Other subsidiaries	BP group
2015 ($ million)				
Net cash provided by operating activities	**925**	**6,628**	**11,580**	**19,133**
Net cash provided by (used in) investing activities	**(925)**	**–**	**(16,375)**	**(17,300)**
Net cash provided by (used in) financing activities	**–**	**(6,659)**	**2,124**	**(4,535)**
Currency translation differences relating to cash and cash equivalents	**–**	**–**	**(672)**	**(672)**
Increase (decrease) in cash and cash equivalents	**–**	**(31)**	**(3,343)**	**(3,374)**
Cash and cash equivalents at beginning of year	**–**	**31**	**29,732**	**29,763**
Cash and cash equivalents at end of year	**–**	**–**	**26,389**	**26,389**

For the year ended 31 December	Issuer: BP Exploration (Alaska) Inc.	Guarantor: BP p.l.c.[a]	Other subsidiaries	BP group
2014 ($ million)				
Net cash provided by operating activities	92	10,464	22,198	32,754
Net cash provided by (used in) investing activities	(92)	–	(19,482)	(19,574)
Net cash provided by (used in) financing activities	–	(10,439)	5,173	(5,266)
Currency translation differences relating to cash and cash equivalents	–	–	(671)	(671)
Increase (decrease) in cash and cash equivalents	–	25	7,218	7,243
Cash and cash equivalents at beginning of year	–	6	22,514	22,520
Cash and cash equivalents at end of year	–	31	29,732	29,763

For the year ended 31 December	Issuer: BP Exploration (Alaska) Inc.	Guarantor: BP p.l.c.[a]	Other subsidiaries	BP group
2013 ($ million)				
Net cash provided by operating activities	746	10,796	9,558	21,100
Net cash provided by (used in) investing activities	(746)	–	(7,109)	(7,855)
Net cash provided by (used in) financing activities	–	(10,799)	399	(10,400)
Currency translation differences relating to cash and cash equivalents	–	–	40	40
Increase (decrease) in cash and cash equivalents	–	(3)	2,888	2,885
Cash and cash equivalents at beginning of year	–	9	19,626	19,635
Cash and cash equivalents at end of year	–	6	22,514	22,520

[a] For 2014 and 2013 BP p.l.c. comparative information certain adjustments have been made to the amounts reported for operating, investing and financing activities, with no overall impact on net cash flow.

Supplementary information on oil and natural gas (unaudited)[a]

The regional analysis presented below is on a continent basis, with separate disclosure for countries that contain 15% or more of the total proved reserves (for subsidiaries plus equity-accounted entities), in accordance with SEC and FASB requirements.

Oil and gas reserves – certain definitions

Unless the context indicates otherwise, the following terms have the meanings shown below:

Proved oil and gas reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
  (A) The area identified by drilling and limited by fluid contacts, if any; and
  (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
  (A) Successful testing by a pilot project in an area of the reservoir with properties no more favourable than in the reservoir as a whole, the operation of an installed programme in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or programme was based; and
  (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Undeveloped oil and gas reserves

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Developed oil and gas reserves

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For details on BP's proved reserves and production compliance and governance processes, see pages 227-232.

[a] 2013 equity-accounted entities information includes BP's share of TNK-BP from 1 January to 20 March, and Rosneft for the period 21 March to 31 December.

Oil and natural gas exploration and production activities

$ million

	Europe		North America		South America	Africa	Asia		Australasia	Total
2015	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Capitalized costs at 31 December[a b]										
Gross capitalized costs										
Proved properties	33,214	10,568	80,716	3,559	11,051	42,807	–	28,474	5,177	215,566
Unproved properties	437	168	5,602	2,377	2,964	4,635	–	2,740	933	19,856
	33,651	10,736	86,318	5,936	14,015	47,442	–	31,214	6,110	235,422
Accumulated depreciation	21,447	7,172	43,290	191	6,251	29,406	–	15,967	2,677	126,401
Net capitalized costs	12,204	3,564	43,028	5,745	7,764	18,036	–	15,247	3,433	109,021
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	17	–	131	–	–	259	–	–	–	407
Unproved	–	–	56	–	(118)	8	–	–	–	(54)
	17	–	187	–	(118)	267	–	–	–	353
Exploration and appraisal costs[c]	178	11	651	75	114	533	5	102	125	1,794
Development	1,784	73	3,662	324	1,299	2,749	–	3,439	128	13,458
Total costs	1,979	84	4,500	399	1,295	3,549	5	3,541	253	15,605
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[d]										
Third parties	496	209	651	14	1,594	1,829	–	800	1,450	7,043
Sales between businesses	1,149	718	7,427	2	33	4,005	–	4,028	340	17,702
	1,645	927	8,078	16	1,627	5,834	–	4,828	1,790	24,745
Exploration expenditure	115	8	960	108	51	1,001	5	53	52	2,353
Production costs	879	313	2,777	77	703	1,521	–	1,083	166	7,519
Production taxes	(273)	–	215	–	214	–	–	834	46	1,036
Other costs (income)[e]	(795)	92	2,460	48	140	358	27	76	215	2,621
Depreciation, depletion and amortization	949	544	3,671	13	673	3,412	–	2,420	322	12,004
Net impairments and (gains) losses on sale of businesses and fixed assets	(390)	17	340	–	101	846	–	105	140	1,159
	485	974	10,423	246	1,882	7,138	32	4,571	941	26,692
Profit (loss) before taxation[f]	1,160	(47)	(2,345)	(230)	(255)	(1,304)	(32)	257	849	(1,947)
Allocable taxes[g]	(930)	159	(857)	(5)	(28)	694	(5)	(66)	472	(566)
Results of operations	2,090	(206)	(1,488)	(225)	(227)	(1,998)	(27)	323	377	(1,381)
Upstream and Rosneft segments replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	1,160	(47)	(2,345)	(230)	(255)	(1,304)	(32)	257	849	(1,947)
Midstream and other activities – subsidiaries[h]	401	110	43	10	211	(39)	(16)	67	14	801
Equity-accounted entities[i]	–	(7)	19	–	370	(552)	1,326	363	–	1,519
Total replacement cost profit before interest and tax	1,561	56	(2,283)	(220)	326	(1,895)	1,278	687	863	373

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes our share of oil and natural gas exploration and production activities of joint operations. They do not include any costs relating to the Gulf of Mexico oil spill. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.

[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[d] Presented net of transportation costs, purchases and sales taxes.

[e] Includes property taxes, other government take and the fair value gain on embedded derivatives of $120 million. The UK region includes a $832 million gain which is offset by corresponding charges, primarily in the US region, relating to the group self-insurance programme.

[f] Excludes the unwinding of the discount on provisions and payables amounting to $164 million which is included in finance costs in the group income statement.

[g] UK region includes the one-off deferred tax impact of the enactment of legislation to reduce the UK supplementary charge tax rate applicable to profits arising in the North Sea from 32% to 20%.

[h] Midstream and other activities excludes inventory holding gains and losses.

[i] BP's share of the profits of equity-accounted entities are included after interest and tax reported by those entities.

$ million

2015

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	–	–	–	–	9,824	–	12,728	3,486	–	26,038
Unproved properties	–	–	–	–	–	–	437	26	–	463
	–	–	–	–	9,824	–	13,165	3,512	–	26,501
Accumulated depreciation	–	–	–	–	4,117	–	2,788	3,458	–	10,363
Net capitalized costs	–	–	–	–	5,707	–	10,377	54	–	16,138
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	–	–	–	–	–	–	16	–	–	16
Unproved	–	–	–	–	–	–	26	–	–	26
	–	–	–	–	–	–	42	–	–	42
Exploration and appraisal costs[d]	–	–	–	–	8	–	123	1	–	132
Development	–	–	–	–	1,128	–	1,702	443	–	3,273
Total costs	–	–	–	–	1,136	–	1,867	444	–	3,447
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	–	–	–	–	2,060	–	–	1,022	–	3,082
Sales between businesses	–	–	–	–	–	–	8,592	19	–	8,611
	–	–	–	–	2,060	–	8,592	1,041	–	11,693
Exploration expenditure	–	–	–	–	3	–	52	–	–	55
Production costs	–	–	–	–	647	–	1,083	168	–	1,898
Production taxes	–	–	–	–	425	–	3,911	388	–	4,724
Other costs (income)	–	–	–	–	(381)	–	284	–	–	(97)
Depreciation, depletion and amortization	–	–	–	–	465	–	992	484	–	1,941
Net impairments and losses on sale of businesses and fixed assets	–	–	–	–	80	–	–	35	–	115
	–	–	–	–	1,239	–	6,322	1,075	–	8,636
Profit (loss) before taxation	–	–	–	–	821	–	2,270	(34)	–	3,057
Allocable taxes	–	–	–	–	504	–	449	1	–	954
Results of operations	–	–	–	–	317	–	1,821	(35)	–	2,103
Upstream and Rosneft segments replacement cost profit before interest and tax from equity-accounted entities										
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	–	317	–	1,821	(35)	–	2,103
Midstream and other activities after tax[g]	–	(7)	19	–	53	(552)	(495)	398	–	(584)
Total replacement cost profit after interest and tax	–	(7)	19	–	370	(552)	1,326	363	–	1,519

[a] Amounts reported for Russia include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia.
[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations as well as downstream activities of Rosneft are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.
[c] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[e] The amounts shown reflect BP's share of equity-accounted entities' costs incurred, and not the costs incurred by BP in acquiring an interest in equity-accounted entities.
[f] Presented net of transportation costs and sales taxes.
[g] Includes interest and adjustment for non-controlling interests. Excludes inventory holding gains and losses.

	Europe		North America		South America	Africa	Asia		Australasia	$ million 2014 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Capitalized costs at 31 December[a b]										
Gross capitalized costs										
Proved properties	31,496	10,578	76,476	3,205	9,796	39,020	–	24,177	5,061	199,809
Unproved properties	395	165	6,294	2,454	2,984	5,769	–	2,773	888	21,722
	31,891	10,743	82,770	5,659	12,780	44,789	–	26,950	5,949	221,531
Accumulated depreciation	21,068	6,610	39,383	190	5,482	25,105	–	13,501	2,215	113,554
Net capitalized costs	10,823	4,133	43,387	5,469	7,298	19,684	–	13,449	3,734	107,977
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	42	–	6	–	–	–	–	557	–	605
Unproved	–	–	346	–	75	57	–	–	–	478
	42	–	352	–	75	57	–	557	–	1,083
Exploration and appraisal costs[c]	279	16	888	109	325	899	–	194	201	2,911
Development	2,067	293	4,792	706	983	2,881	–	3,205	169	15,096
Total costs	2,388	309	6,032	815	1,383	3,837	–	3,956	370	19,090
Results of operations for the year ended 31 December[a d]										
Sales and other operating revenues[e]										
Third parties	529	77	1,218	4	2,802	2,536	–	1,135	2,574	10,875
Sales between businesses	1,069	1,662	14,894	15	450	6,289	–	6,951	624	31,954
	1,598	1,739	16,112	19	3,252	8,825	–	8,086	3,198	42,829
Exploration expenditure	94	47	1,294	63	502	860	–	712	60	3,632
Production costs	979	436	3,492	34	783	1,542	–	1,289	232	8,787
Production taxes	(234)	–	690	–	175	–	–	2,234	93	2,958
Other costs (income)[f]	(1,515)	77	3,260	55	284	120	57	(69)	343	2,612
Depreciation, depletion and amortization	506	676	3,805	4	678	3,343	–	2,461	255	11,728
Net impairments and (gains) losses on sale of businesses and fixed assets	2,537	2,278	(28)	–	11	1,128	–	391	–	6,317
	2,367	3,514	12,513	156	2,433	6,993	57	7,018	983	36,034
Profit (loss) before taxation[g]	(769)	(1,775)	3,599	(137)	819	1,832	(57)	1,068	2,215	6,795
Allocable taxes	(1,383)	(1,108)	1,269	15	865	1,216	3	67	1,161	2,105
Results of operations	614	(667)	2,330	(152)	(46)	616	(60)	1,001	1,054	4,690
Upstream and Rosneft segments replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	(769)	(1,775)	3,599	(137)	819	1,832	(57)	1,068	2,215	6,795
Midstream and other activities – subsidiaries[h]	163	99	703	130	175	(170)	(26)	(63)	14	1,025
Equity-accounted entities[i]	–	62	23	–	480	(33)	2,125	557	–	3,214
Total replacement cost profit before interest and tax	(606)	(1,614)	4,325	(7)	1,474	1,629	2,042	1,562	2,229	11,034

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes our share of oil and natural gas exploration and production activities of joint operations. They do not include any costs relating to the Gulf of Mexico oil spill. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.

[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[d] Amendments have been made to previously published amounts for the Australasia region with no overall effect on total replacement cost profit before interest and tax.

[e] Presented net of transportation costs, purchases and sales taxes.

[f] Includes property taxes, other government take and the fair value gain on embedded derivatives of $430 million. The UK region includes a $1,016 million gain which is offset by corresponding charges, primarily in the US region, relating to the group self-insurance programme.

[g] Excludes the unwinding of the discount on provisions and payables amounting to $207 million which is included in finance costs in the group income statement.

[h] Midstream and other activities excludes inventory holding gains and losses.

[i] BP's share of the profits of equity-accounted entities are included after interest and tax reported by those entities.

	Europe		North America		South America	Africa	Asia		Australasia	$ million 2014 Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	–	–	–	–	8,719	–	12,971	3,073	–	24,763
Unproved properties	–	–	–	–	5	–	376	25	–	406
	–	–	–	–	8,724	–	13,347	3,098	–	25,169
Accumulated depreciation	–	–	–	–	3,652	–	2,031	2,986	–	8,669
Net capitalized costs	–	–	–	–	5,072	–	11,316	112	–	16,500
Costs incurred for the year ended 31 December[b c]										
Acquisition of properties[d]										
Proved	–	–	–	–	–	–	(46)	–	–	(46)
Unproved	–	–	–	–	–	–	87	–	–	87
	–	–	–	–	–	–	41	–	–	41
Exploration and appraisal costs[e]	–	–	–	–	5	–	128	4	–	137
Development[f]	–	–	–	–	1,026	–	1,913	326	–	3,265
Total costs	–	–	–	–	1,031	–	2,082	330	–	3,443
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[g]										
Third parties	–	–	–	–	2,472	–	–	1,257	–	3,729
Sales between businesses	–	–	–	–	–	–	10,972	19	–	10,991
	–	–	–	–	2,472	–	10,972	1,276	–	14,720
Exploration expenditure	–	–	–	–	4	–	62	1	–	67
Production costs	–	–	–	–	567	–	1,318	152	–	2,037
Production taxes	–	–	–	–	721	–	5,214	692	–	6,627
Other costs (income)	–	–	–	–	4	–	302	–	–	306
Depreciation, depletion and amortization	–	–	–	–	370	–	1,509	371	–	2,250
Net impairments and losses on sale of businesses and fixed assets	–	–	–	–	25	–	–	–	–	25
	–	–	–	–	1,691	–	8,405	1,216	–	11,312
Profit (loss) before taxation	–	–	–	–	781	–	2,567	60	–	3,408
Allocable taxes	–	–	–	–	402	–	637	29	–	1,068
Results of operations	–	–	–	–	379	–	1,930	31	–	2,340
Upstream and Rosneft segments replacement cost profit before interest and tax from equity-accounted entities										
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	–	379	–	1,930	31	–	2,340
Midstream and other activities after tax[h]	–	62	23	–	101	(33)	195	526	–	874
Total replacement cost profit after interest and tax	–	62	23	–	480	(33)	2,125	557	–	3,214

[a] Amounts reported for Russia include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia.
[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations as well as downstream activities of Rosneft are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.
[c] The amounts shown reflect BP's share of equity-accounted entities' costs incurred, and not the costs incurred by BP in acquiring an interest in equity-accounted entities.
[d] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[e] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[f] An amendment has been made to the amount previously disclosed for the Rest of Asia region.
[g] Presented net of transportation costs and sales taxes.
[h] Includes interest and adjustment for non-controlling interests. Excludes inventory holding gains and losses.

Oil and natural gas exploration and production activities – continued

$ million

2013	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Capitalized costs at 31 December[a b]										
Gross capitalized costs										
Proved properties	29,314	10,040	75,313	2,501	8,809	35,720	–	20,726	4,681	187,104
Unproved properties	316	195	6,816	2,408	3,366	5,079	–	2,756	805	21,741
	29,630	10,235	82,129	4,909	12,175	40,799	–	23,482	5,486	208,845
Accumulated depreciation	18,707	3,650	38,236	193	5,063	20,082	–	10,069	1,962	97,962
Net capitalized costs	10,923	6,585	43,893	4,716	7,112	20,717	–	13,413	3,524	110,883
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	–	–	1	–	7	–	–	–	–	8
Unproved	–	–	158	–	284	30	–	7	–	479
	–	–	159	–	291	30	–	7	–	487
Exploration and appraisal costs[c]	178	14	1,291	194	951	883	–	1,090	210	4,811
Development	1,942	455	4,877	569	683	2,755	–	2,082	189	13,552
Total costs	2,120	469	6,327	763	1,925	3,668	–	3,179	399	18,850
Results of operations for the year ended 31 December[d]										
Sales and other operating revenues[e]										
Third parties	1,129	183	934	5	2,413	3,195	–	1,005	2,466	11,330
Sales between businesses	1,661	1,280	14,047	12	1,154	6,518	–	11,432	639	36,743
	2,790	1,463	14,981	17	3,567	9,713	–	12,437	3,105	48,073
Exploration expenditure	280	17	437	28	1,477	387	–	768	47	3,441
Production costs	1,102	430	3,691	42	892	1,623	–	1,091	187	9,058
Production taxes	(35)	–	1,112	–	184	–	–	5,660	126	7,047
Other costs (income)[f]	(1,731)	86	3,241	55	322	89	65	84	394	2,605
Depreciation, depletion and amortization	504	490	3,268	–	559	3,132	–	2,174	207	10,334
Net impairments and (gains) losses on sale of businesses and fixed assets	118	15	(80)	–	129	29	–	(16)	230	425
	238	1,038	11,669	125	3,563	5,260	65	9,761	1,191	32,910
Profit (loss) before taxation[g]	2,552	425	3,312	(108)	4	4,453	(65)	2,676	1,914	15,163
Allocable taxes	554	475	1,204	(26)	642	1,925	(2)	682	845	6,299
Results of operations	1,998	(50)	2,108	(82)	(638)	2,528	(63)	1,994	1,069	8,864
Upstream, Rosneft and TNK-BP segments replacement cost profit before interest and tax[d]										
Exploration and production activities – subsidiaries (as above)	2,552	425	3,312	(108)	4	4,453	(65)	2,676	1,914	15,163
Midstream and other activities – subsidiaries[h]	244	(40)	296	(14)	153	(154)	(4)	(29)	10	462
TNK-BP gain on sale	–	–	–	–	–	–	12,500	–	–	12,500
Equity-accounted entities[i]	–	28	17	–	405	24	2,158	553	–	3,185
Total replacement cost profit before interest and tax	2,796	413	3,625	(122)	562	4,323	14,589	3,200	1,924	31,310

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes our share of oil and natural gas exploration and production activities of joint operations. They do not include any costs relating to the Gulf of Mexico oil spill. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.

[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[d] Amendments have been made to previously published amounts for the Australasia region with no overall effect on total replacement cost before interest and tax.

[e] Presented net of transportation costs, purchases and sales taxes.

[f] Includes property taxes, other government take and the fair value gain on embedded derivatives of $459 million. The UK region includes a $1,055 million gain which is offset by corresponding charges, primarily in the US region, relating to the group self-insurance programme.

[g] Excludes the unwinding of the discount on provisions and payables amounting to $141 million which is included in finance costs in the group income statement.

[h] Midstream and other activities excludes inventory holding gains and losses.

[i] BP's share of the profits of equity-accounted entities are included after interest and tax reported by those entities.

	Europe		North America		South America	Africa	Asia		Australasia	$ million 2013 Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	–	–	–	–	7,648	–	18,942	4,239	–	30,829
Unproved properties	–	–	–	–	29	–	638	21	–	688
	–	–	–	–	7,677	–	19,580	4,260	–	31,517
Accumulated depreciation	–	–	–	–	3,282	–	1,077	4,061	–	8,420
Net capitalized costs	–	–	–	–	4,395	–	18,503	199	–	23,097
Costs incurred for the year ended 31 December[b c d]										
Acquisition of properties										
Proved	–	–	–	–	–	–	1,816	–	–	1,816
Unproved	–	–	–	–	–	–	657	–	–	657
	–	–	–	–	–	–	2,473	–	–	2,473
Exploration and appraisal costs[e]	–	–	–	–	8	–	133	12	–	153
Development[f]	–	–	–	–	714	–	1,860	423	–	2,997
Total costs	–	–	–	–	722	–	4,466	435	–	5,623
Results of operations for the year ended 31 December[b f]										
Sales and other operating revenues[g]										
Third parties	–	–	–	–	2,294	–	435	4,591	–	7,320
Sales between businesses	–	–	–	–	–	–	9,679	14	–	9,693
	–	–	–	–	2,294	–	10,114	4,605	–	17,013
Exploration expenditure	–	–	–	–	–	–	126	1	–	127
Production costs	–	–	–	–	586	–	1,177	382	–	2,145
Production taxes	–	–	–	–	630	–	4,511	3,383	–	8,524
Other costs (income)	–	–	–	–	6	–	94	–	–	100
Depreciation, depletion and amortization	–	–	–	–	317	–	1,232	648	–	2,197
Net impairments and losses on sale of businesses and fixed assets	–	–	–	–	–	–	37	–	–	37
	–	–	–	–	1,539	–	7,177	4,414	–	13,130
Profit (loss) before taxation	–	–	–	–	755	–	2,937	191	–	3,883
Allocable taxes	–	–	–	–	460	–	367	40	–	867
Results of operations	–	–	–	–	295	–	2,570	151	–	3,016
Upstream, Rosneft and TNK-BP segments replacement cost profit before interest and tax from equity-accounted entities										
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	–	295	–	2,570	151	–	3,016
Midstream and other activities after tax[h]	–	28	17	–	110	24	(412)	402	–	169
Total replacement cost profit after interest and tax	–	28	17	–	405	24	2,158	553	–	3,185

[a] Amounts reported for Russia include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia.
[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations as well as downstream activities of TNK-BP and Rosneft are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.
[c] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[d] The amounts shown reflect BP's share of equity-accounted entities' costs incurred, and not the costs incurred by BP in acquiring an interest in equity-accounted entities.
[e] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[f] Amendments have been made to previously published numbers for the Rest of Asia region. The amendments have no overall effect on results of operations.
[g] Presented net of transportation costs and sales taxes.
[h] Includes interest and adjustment for non-controlling interests. Excludes inventory holding gains and losses.

Movements in estimated net proved reserves

Crude oil[a b]										million barrels 2015
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	159	95	1,030	9	10	317	–	384	40	2,044
Undeveloped	329	22	664	163	22	120	–	197	19	1,538
	488	117	1,694	172	32	437	–	581	59	3,582
Changes attributable to										
Revisions of previous estimates	(23)	2	(130)	39	(2)	80	–	295	(2)	260
Improved recovery	–	–	15	–	–	2	–	–	–	18
Purchases of reserves-in-place	1	–	–	–	–	6	–	–	–	7
Discoveries and extensions	–	–	3	42	–	2	–	–	–	47
Production[d]	(27)	(14)	(115)	(1)	(5)	(98)	–	(87)	(6)	(353)
Sales of reserves-in-place	(1)	–	–	–	–	–	–	–	–	(1)
	(48)	(12)	(227)	80	(6)	(8)	–	208	(8)	(21)
At 31 December[e]										
Developed	141	86	890	46	8	340	–	598	35	2,146
Undeveloped	298	19	577	205	18	89	–	192	16	1,414
	440	106	1,467	252	26	429	–	790	51	3,560
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	–	–	–	–	316	2	2,997	89	–	3,405
Undeveloped	–	–	–	–	314	–	1,933	11	–	2,258
	–	–	–	1	630	2	4,930	101	–	5,663
Changes attributable to										
Revisions of previous estimates	–	–	–	–	9	–	(23)	3	–	(11)
Improved recovery	–	–	–	–	3	–	–	–	–	3
Purchases of reserves-in-place	–	–	–	–	–	–	28	–	–	28
Discoveries and extensions	–	–	–	–	9	–	185	–	–	194
Production	–	–	–	–	(28)	–	(295)	(35)	–	(358)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	(8)	–	(105)	(32)	–	(146)
At 31 December[g]										
Developed	–	–	–	–	311	2	2,844	68	–	3,225
Undeveloped	–	–	–	–	311	–	1,981	–	–	2,292
	–	–	–	–	622	2	4,825	68	–	5,517
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	159	95	1,030	9	326	319	2,997	473	40	5,448
Undeveloped	329	22	664	164	336	120	1,933	208	19	3,796
	488	117	1,694	173	662	439	4,930	682	59	9,244
At 31 December										
Developed	141	86	890	47	319	342	2,844	666	35	5,371
Undeveloped	298	19	577	205	329	89	1,981	192	16	3,707
	440	106	1,467	252	648	431	4,825	858	51	9,078

[a] Crude oil includes condensate and bitumen. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 23 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Includes 8 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 70 million barrels of crude oil in respect of the 1.27% non-controlling interest in Rosneft, including 28 mmbbl held through BP's equity-accounted interest in Taas-Yuryakh Neftegazodobycha.
[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 4,823 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 26 million barrels in Venezuela and 4,797 million barrels in Russia.

Movements in estimated net proved reserves – continued

million barrels

Natural gas liquids[a b]										2015
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	6	13	323	–	11	5	–	–	6	364
Undeveloped	3	1	104	–	28	7	–	–	3	146
	9	14	427	–	39	12	–	–	10	510
Changes attributable to										
Revisions of previous estimates	2	–	(80)	–	–	6	–	–	3	(69)
Improved recovery	–	–	12	–	–	–	–	–	–	12
Purchases of reserves-in-place	–	–	3	–	–	–	–	–	–	4
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production[c]	(2)	(2)	(23)	–	(4)	(3)	–	–	(1)	(34)
Sales of reserves-in-place	–	–	(1)	–	–	–	–	–	–	(1)
	–	(2)	(88)	–	(4)	3	–	–	2	(88)
At 31 December[d]										
Developed	5	11	269	–	7	5	–	–	9	308
Undeveloped	4	1	70	–	28	10	–	–	2	115
	10	12	339	–	35	15	–	–	12	422
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	–	–	–	–	–	15	30	–	–	46
Undeveloped	–	–	–	–	–	–	16	–	–	16
	–	–	–	–	–	15	46	–	–	62
Changes attributable to										
Revisions of previous estimates	–	–	–	–	–	(3)	1	–	–	(2)
Improved recovery	–	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production	–	–	–	–	–	–	–	–	–	–
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	(3)	1	–	–	(2)
At 31 December[f]										
Developed	–	–	–	–	–	13	32	–	–	45
Undeveloped	–	–	–	–	–	–	15	–	–	15
	–	–	–	–	–	13	47	–	–	60
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	6	13	323	–	11	20	30	–	6	410
Undeveloped	3	1	104	–	28	7	16	–	3	163
	9	14	427	–	39	27	46	–	10	572
At 31 December										
Developed	5	11	269	–	7	18	32	–	9	352
Undeveloped	4	1	70	–	28	10	15	–	2	130
	10	12	339	–	35	28	47	–	12	482

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 4 thousand barrels per day for equity-accounted entities.
[d] Includes 11 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Total proved NGL reserves held as part of our equity interest in Rosneft is 47 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 47 million barrels in Russia.

Movements in estimated net proved reserves – continued

million barrels

Total liquids[a b]	Europe		North America		South America	Africa	Asia		Australasia	2015 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	166	108	1,352	9	21	322	–	384	46	2,407
Undeveloped	332	23	769	163	50	127	–	197	22	1,684
	497	131	2,121	172	71	449	–	581	68	4,092
Changes attributable to										
Revisions of previous estimates	(20)	2	(210)	39	(2)	86	–	295	1	191
Improved recovery	–	–	28	–	–	2	–	–	–	30
Purchases of reserves-in-place	1	–	3	–	–	6	–	–	–	11
Discoveries and extensions	–	–	4	42	–	2	–	–	–	48
Production[d]	(29)	(16)	(138)	(1)	(8)	(101)	–	(87)	(7)	(387)
Sales of reserves-in-place	(1)	–	(1)	–	–	–	–	–	–	(2)
	(48)	(14)	(315)	80	(10)	(5)	–	208	(6)	(109)
At 31 December[e]										
Developed	147	98	1,159	46	15	346	–	598	45	2,453
Undeveloped	302	20	647	205	46	99	–	192	18	1,529
	449	117	1,806	252	61	444	–	790	63	3,982
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	–	–	–	–	316	17	3,028	89	–	3,451
Undeveloped	–	–	–	–	314	–	1,949	11	–	2,274
	–	–	–	1	630	17	4,976	101	–	5,725
Changes attributable to										
Revisions of previous estimates	–	–	–	–	9	(3)	(22)	3	–	(13)
Improved recovery	–	–	–	–	3	–	–	–	–	3
Purchases of reserves-in-place	–	–	–	–	–	–	28	–	–	28
Discoveries and extensions	–	–	–	–	9	–	185	–	–	194
Production	–	–	–	–	(28)	–	(295)	(35)	–	(358)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	(1)	(8)	(3)	(104)	(32)	–	(147)
At 31 December[g h]										
Developed	–	–	–	–	311	14	2,876	68	–	3,270
Undeveloped	–	–	–	–	312	–	1,996	–	–	2,307
	–	–	–	–	622	14	4,872	68	–	5,577
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	166	108	1,352	9	337	339	3,028	473	46	5,858
Undeveloped	332	23	769	164	364	127	1,949	208	22	3,958
	497	131	2,121	173	701	466	4,976	682	68	9,817
At 31 December										
Developed	147	98	1,159	47	326	360	2,876	666	45	5,723
Undeveloped	302	20	647	205	357	99	1,996	192	18	3,836
	449	117	1,806	252	684	459	4,872	858	63	9,560

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 23 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 4 thousand barrels per day for equity-accounted entities.
[e] Also includes 19 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] Includes 70 million barrels in respect of the non-controlling interest in Rosneft, including 28 mmboe held through BP's equity-accounted interest in Taas-Yuryakh Neftegazodobycha.
[h] Total proved liquid reserves held as part of our equity interest in Rosneft is 4,871 million barrels, comprising less than 1 million barrels in Canada, 26 million barrels in Venezuela, less than 1 million barrels in Vietnam and 4,844 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
										billion cubic feet
										2015
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	382	300	7,168	17	2,352	901	–	1,688	3,316	16,124
Undeveloped	386	19	2,447	–	6,313	1,597	–	3,892	1,719	16,372
	768	318	9,615	17	8,666	2,497	–	5,580	5,035	32,496
Changes attributable to										
Revisions of previous estimates	(12)	14	(1,120)	(13)	132	203	–	(165)	13	(948)
Improved recovery	4	–	432	–	–	7	–	–	–	443
Purchases of reserves-in-place	–	–	65	–	29	554	–	–	–	648
Discoveries and extensions	–	–	5	–	–	174	–	–	–	179
Production[c]	(65)	(44)	(628)	(4)	(709)	(248)	–	(157)	(297)	(2,151)
Sales of reserves-in-place	(5)	–	(6)	–	(58)	(35)	–	–	–	(104)
	(77)	(30)	(1,252)	(17)	(605)	654	–	(322)	(284)	(1,933)
At 31 December[d]										
Developed	348	274	6,257	–	2,071	847	–	1,803	3,408	15,009
Undeveloped	343	14	2,105	–	5,989	2,305	–	3,455	1,343	15,553
	691	288	8,363	–	8,060	3,152	–	5,257	4,751	30,563
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	–	–	–	1	1,228	400	4,674	60	–	6,363
Undeveloped	–	–	–	1	717	–	5,111	9	–	5,837
	–	–	–	1	1,945	400	9,785	69	–	12,200
Changes attributable to										
Revisions of previous estimates	–	–	–	(1)	81	(14)	1,604	(2)	–	1,669
Improved recovery	–	–	–	–	8	–	–	–	–	8
Purchases of reserves-in-place	–	–	–	–	–	–	5	–	–	5
Discoveries and extensions	–	–	–	–	209	–	175	–	–	384
Production[c]	–	–	–	–	(182)	–	(430)	(19)	–	(632)
Sales of reserves-in-place	–	–	–	–	(1)	–	–	–	–	(1)
	–	–	–	(1)	116	(14)	1,354	(21)	–	1,434
At 31 December[f g]										
Developed	–	–	–	1	1,463	386	4,962	44	–	6,856
Undeveloped	–	–	–	–	598	–	6,176	4	–	6,778
	–	–	–	1	2,061	386	11,139	48	–	13,634
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	382	300	7,168	18	3,581	1,301	4,674	1,748	3,316	22,487
Undeveloped	386	19	2,447	1	7,030	1,597	5,111	3,901	1,719	22,209
	768	318	9,615	18	10,610	2,897	9,785	5,648	5,035	44,695
At 31 December										
Developed	348	274	6,257	1	3,534	1,233	4,962	1,847	3,408	21,865
Undeveloped	343	14	2,105	–	6,587	2,305	6,176	3,459	1,343	22,331
	691	288	8,363	1	10,121	3,538	11,139	5,305	4,751	44,197

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Includes 175 billion cubic feet of natural gas consumed in operations, 146 billion cubic feet in subsidiaries, 29 billion cubic feet in equity-accounted entities.
[d] Includes 2,359 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 129 billion cubic feet of natural gas in respect of the 0.23% non-controlling interest in Rosneft including 5 billion cubic feet held through BP's equity-accounted interest in Taas-Yuryakh Neftegazodobycha.
[g] Total proved gas reserves held as part of our equity interest in Rosneft is 11,169 billion cubic feet, comprising 1 billion cubic feet in Canada, 13 billion cubic feet in Venezuela, 22 billion cubic feet in Vietnam and 11,133 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]	Europe		North America		South America	Africa	Asia		Australasia	2015 Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	232	160	2,588	12	426	477	–	675	618	5,187
Undeveloped	398	26	1,191	163	1,139	403	–	868	319	4,507
	630	186	3,779	175	1,565	880	–	1,543	937	9,695
Changes attributable to										
Revisions of previous estimates	(22)	4	(403)	36	21	121	–	267	4	27
Improved recovery	1	–	102	–	–	3	–	–	–	106
Purchases of reserves-in-place	1	–	15	–	5	102	–	–	–	122
Discoveries and extensions	–	–	4	42	–	32	–	–	–	79
Production[e f]	(40)	(23)	(247)	(2)	(130)	(144)	–	(114)	(58)	(758)
Sales of reserves-in-place	(1)	–	(2)	–	(10)	(6)	–	–	–	(19)
	(62)	(19)	(531)	77	(114)	108	–	153	(55)	(443)
At 31 December[g]										
Developed	207	145	2,238	46	373	492	–	909	632	5,041
Undeveloped	362	22	1,010	205	1,078	496	–	788	250	4,211
	568	167	3,248	252	1,451	988	–	1,696	882	9,252
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed	–	–	–	–	528	86	3,834	100	–	4,548
Undeveloped	–	–	–	1	438	–	2,830	13	–	3,280
	–	–	–	1	965	86	6,663	112	–	7,828
Changes attributable to										
Revisions of previous estimates	–	–	–	(1)	23	(5)	255	3	–	274
Improved recovery	–	–	–	–	5	–	–	–	–	5
Purchases of reserves-in-place	–	–	–	–	–	–	29	–	–	29
Discoveries and extensions	–	–	–	–	45	–	215	–	–	260
Production[f]	–	–	–	–	(60)	–	(369)	(39)	–	(467)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	(1)	12	(5)	129	(36)	–	100
At 31 December[i j]										
Developed	–	–	–	–	563	81	3,732	76	–	4,452
Undeveloped	–	–	–	–	415	–	3,061	1	–	3,476
	–	–	–	–	978	81	6,792	77	–	7,928
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	232	160	2,588	12	954	563	3,834	775	618	9,735
Undeveloped	398	26	1,191	164	1,576	403	2,830	881	319	7,788
	630	186	3,779	176	2,530	966	6,663	1,656	937	17,523
At 31 December										
Developed	207	145	2,238	47	936	573	3,732	984	632	9,493
Undeveloped	362	22	1,010	205	1,493	496	3,061	788	250	7,687
	568	167	3,248	252	2,429	1,069	6,792	1,773	882	17,180

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.
[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 23 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[e] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 4 thousand barrels per day for equity-accounted entities.
[f] Includes 30 million barrels of oil equivalent of natural gas consumed in operations, 25 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities.
[g] Includes 425 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[i] Includes 70 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 28 mmboe held through BP's equity-accounted interest in Taas-Yuryakh Neftegazodobycha.
[j] Total proved reserves held as part of our equity interest in Rosneft is 6,796 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada, 28 million barrels of oil equivalent in Venezuela, 4 million barrels of oil equivalent in Vietnam and 6,764 million barrels of oil equivalent in Russia.

million barrels

Crude oil[a b]										2014
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	160	147	1,007	–	15	316	–	320	49	2,013
Undeveloped	374	53	752	188	17	180	–	202	19	1,785
	534	200	1,760	188	31	495	–	522	69	3,798
Changes attributable to										
Revisions of previous estimates	(41)	(68)	87	(16)	9	20	–	96	(2)	85
Improved recovery	2	–	16	–	1	3	–	–	–	23
Purchases of reserves-in-place	5	–	–	–	–	–	–	12	–	17
Discoveries and extensions	5	–	–	–	1	–	–	8	–	13
Production[d]	(17)	(15)	(123)	–	(5)	(81)	–	(57)	(7)	(305)
Sales of reserves-in-place	–	–	(45)	–	(5)	–	–	–	–	(50)
	(46)	(82)	(66)	(16)	1	(58)	–	59	(9)	(217)
At 31 December[e]										
Developed	159	95	1,030	9	10	317	–	384	40	2,044
Undeveloped	329	22	664	163	22	120	–	197	19	1,538
	488	117	1,694	172	32	437	–	581	59	3,581
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	–	–	–	–	316	2	2,970	120	–	3,407
Undeveloped	–	–	–	1	314	2	1,858	7	–	2,182
	–	–	–	1	630	4	4,828	127	–	5,590
Changes attributable to										
Revisions of previous estimates	–	–	–	–	4	(2)	213	9	–	224
Improved recovery	–	–	–	–	12	–	–	–	–	12
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	10	–	187	–	–	197
Production	–	–	–	–	(26)	–	(297)	(36)	–	(359)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	(2)	103	(27)	–	74
At 31 December[g]										
Developed	–	–	–	–	316	2	2,997	89	–	3,405
Undeveloped	–	–	–	–	314	–	1,933	11	–	2,258
	–	–	–	1	630	2	4,930	101	–	5,663
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	160	147	1,007	–	331	317	2,970	440	49	5,421
Undeveloped	374	53	752	189	331	182	1,858	209	19	3,965
	534	200	1,760	189	661	499	4,828	649	69	9,388
At 31 December										
Developed	159	95	1,030	9	326	319	2,997	473	40	5,448
Undeveloped	329	22	664	164	336	120	1,933	208	19	3,796
	488	117	1,694	173	662	439	4,930	682	59	9,244

[a] Crude oil includes condensate and bitumen. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Includes 10 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 38 million barrels of crude oil in respect of the 0.15% non-controlling interest in Rosneft.
[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 4,961 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 30 million barrels in Venezuela and 4,930 million barrels in Russia.

										million barrels
Natural gas liquids[a b]										2014
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	9	16	290	–	14	4	–	–	8	342
Undeveloped	6	2	155	–	28	15	–	–	3	209
	15	18	444	–	43	20	–	–	10	551
Changes attributable to										
Revisions of previous estimates	(6)	(2)	15	–	–	(6)	–	–	–	1
Improved recovery	–	–	13	–	–	–	–	–	–	13
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	1
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production[c]	(1)	(2)	(27)	–	(4)	(2)	–	–	(1)	(36)
Sales of reserves-in-place	–	–	(18)	–	–	–	–	–	–	(18)
	(6)	(4)	(17)	–	(4)	(8)	–	–	(1)	(40)
At 31 December[d]										
Developed	6	13	323	–	11	5	–	–	6	364
Undeveloped	3	1	104	–	28	7	–	–	3	146
	9	14	427	–	39	12	–	–	10	510
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	–	–	–	–	–	8	94	–	–	103
Undeveloped	–	–	–	–	–	8	21	–	–	29
	–	–	–	–	–	16	115	–	–	131
Changes attributable to										
Revisions of previous estimates	–	–	–	–	–	–	(69)	–	–	(69)
Improved recovery	–	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production	–	–	–	–	–	–	–	–	–	–
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	(1)	(69)	–	–	(69)
At 31 December[f]										
Developed	–	–	–	–	–	15	30	–	–	46
Undeveloped	–	–	–	–	–	–	16	–	–	16
	–	–	–	–	–	15	46	–	–	62
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	9	16	290	–	14	13	94	–	8	444
Undeveloped	6	2	155	–	28	23	21	–	3	238
	15	18	444	–	43	36	115	–	10	682
At 31 December										
Developed	6	13	323	–	11	20	30	–	6	410
Undeveloped	3	1	104	–	28	7	16	–	3	163
	9	14	427	–	39	27	46	–	10	572

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.
[d] Includes 12 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Total proved NGL reserves held as part of our equity interest in Rosneft is 47 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 46 million barrels in Russia.

Movements in estimated net proved reserves – continued

Total liquids[a b]										million barrels 2014
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	169	163	1,297	–	29	320	–	320	57	2,354
Undeveloped	380	55	907	188	46	195	–	202	22	1,994
	549	217	2,204	188	74	515	–	523	78	4,348
Changes attributable to										
Revisions of previous estimates	(47)	(70)	101	(16)	9	14	–	96	(2)	86
Improved recovery	2	–	28	–	1	3	–	–	–	36
Purchases of reserves-in-place	5	–	–	–	–	–	–	12	–	18
Discoveries and extensions	5	–	–	–	1	–	–	8	–	14
Production[d]	(17)	(17)	(150)	–	(9)	(83)	–	(57)	(8)	(341)
Sales of reserves-in-place	–	–	(63)	–	(5)	–	–	–	–	(68)
	(52)	(86)	(83)	(16)	(3)	(66)	–	59	(10)	(257)
At 31 December[e]										
Developed	166	108	1,352	9	21	322	–	384	46	2,407
Undeveloped	332	23	769	163	50	127	–	197	22	1,684
	497	131	2,121	172	71	449	–	581	68	4,092
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	–	–	–	–	316	10	3,063	120	–	3,510
Undeveloped	–	–	–	1	314	10	1,879	7	–	2,210
	–	–	–	1	630	20	4,943	127	–	5,721
Changes attributable to										
Revisions of previous estimates	–	–	–	–	4	(3)	144	9	–	155
Improved recovery	–	–	–	–	12	–	–	–	–	12
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	10	–	187	–	–	197
Production	–	–	–	–	(26)	–	(297)	(36)	–	(359)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	(3)	34	(27)	–	4
At 31 December[g h]										
Developed	–	–	–	–	316	17	3,028	89	–	3,451
Undeveloped	–	–	–	–	314	–	1,949	11	–	2,274
	–	–	–	1	630	17	4,976	101	–	5,725
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	169	163	1,297	–	345	331	3,063	440	57	5,865
Undeveloped	380	55	907	188	359	205	1,879	209	22	4,204
	549	217	2,204	189	704	535	4,943	650	78	10,069
At 31 December										
Developed	166	108	1,352	9	337	339	3,028	473	46	5,858
Undeveloped	332	23	769	164	364	127	1,949	208	22	3,958
	497	131	2,121	173	701	466	4,976	682	68	9,817

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.
[e] Also includes 21 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] Includes 38 million barrels in respect of the non-controlling interest in Rosneft.
[h] Total proved liquid reserves held as part of our equity interest in Rosneft is 5,007 million barrels, comprising 1 million barrels in Canada, 30 million barrels in Venezuela, less than 1 million barrels in Vietnam and 4,976 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
										billion cubic feet
										2014
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	643	364	7,122	10	3,109	961	–	1,519	3,932	17,660
Undeveloped	314	39	2,825	–	6,116	1,807	–	3,671	1,755	16,527
	957	403	9,947	10	9,225	2,768	–	5,190	5,687	34,187
Changes attributable to										
Revisions of previous estimates	(260)	(46)	(29)	11	(258)	(84)	–	(34)	(351)	(1,050)
Improved recovery	7	–	582	–	220	28	–	–	–	838
Purchases of reserves-in-place	1	–	5	–	–	–	–	322	–	328
Discoveries and extensions	94	–	2	–	271	4	–	267	–	637
Production[c]	(30)	(40)	(625)	(4)	(792)	(218)	–	(165)	(302)	(2,177)
Sales of reserves-in-place	–	–	(266)	–	–	–	–	–	–	(266)
	(189)	(85)	(332)	7	(559)	(271)	–	389	(652)	(1,691)
At 31 December[d]										
Developed	382	300	7,168	17	2,352	901	–	1,688	3,316	16,124
Undeveloped	386	19	2,447	–	6,313	1,597	–	3,892	1,719	16,372
	768	318	9,615	17	8,666	2,497	–	5,580	5,035	32,496
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	–	–	–	–	1,364	230	4,171	72	–	5,837
Undeveloped	–	–	–	1	747	135	5,054	14	–	5,951
	–	–	–	1	2,111	365	9,225	86	–	11,788
Changes attributable to										
Revisions of previous estimates	–	–	–	1	(87)	38	767	1	–	720
Improved recovery	–	–	–	–	23	–	–	–	–	23
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	69	–	183	–	–	252
Production[c]	–	–	–	–	(172)	(3)	(390)	(18)	–	(583)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	(166)	35	560	(17)	–	412
At 31 December[f g]										
Developed	–	–	–	1	1,228	400	4,674	60	–	6,363
Undeveloped	–	–	–	1	717	–	5,111	9	–	5,837
	–	–	–	1	1,945	400	9,785	69	–	12,200
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	643	364	7,122	10	4,473	1,191	4,171	1,591	3,932	23,497
Undeveloped	314	39	2,825	1	6,863	1,942	5,054	3,685	1,755	22,478
	957	403	9,947	11	11,336	3,133	9,225	5,276	5,687	45,975
At 31 December										
Developed	382	300	7,168	18	3,581	1,301	4,674	1,748	3,316	22,487
Undeveloped	386	19	2,447	1	7,030	1,597	5,111	3,901	1,719	22,209
	768	318	9,615	18	10,610	2,897	9,785	5,648	5,035	44,695

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Includes 181 billion cubic feet of natural gas consumed in operations, 151 billion cubic feet in subsidiaries, 29 billion cubic feet in equity-accounted entities.
[d] Includes 2,519 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 91 billion cubic feet of natural gas in respect of the 0.18% non-controlling interest in Rosneft.
[g] Total proved gas reserves held as part of our equity interest in Rosneft is 9,827 billion cubic feet, comprising 1 billion cubic feet in Canada, 14 billion cubic feet in Venezuela, 26 billion cubic feet in Vietnam and 9,785 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
2014	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	280	225	2,525	2	564	486	–	582	735	5,399
Undeveloped	434	62	1,394	188	1,100	507	–	835	324	4,844
	714	287	3,919	190	1,664	993	–	1,417	1,059	10,243
Changes attributable to										
Revisions of previous estimates	(91)	(78)	96	(14)	(36)	(1)	–	90	(62)	(96)
Improved recovery	3	–	129	–	39	8	–	–	–	180
Purchases of reserves-in-place	6	–	1	–	–	–	–	68	–	74
Discoveries and extensions	21	–	1	–	47	1	–	54	–	123
Production[e f]	(23)	(24)	(258)	(1)	(146)	(121)	–	(86)	(60)	(717)
Sales of reserves-in-place	–	–	(109)	–	(5)	–	–	–	–	(114)
	(84)	(101)	(140)	(14)	(99)	(113)	–	126	(122)	(548)
At 31 December[g]										
Developed	232	160	2,588	12	426	477	–	675	618	5,187
Undeveloped	398	26	1,191	163	1,139	403	–	868	319	4,507
	630	186	3,779	175	1,565	880	–	1,543	937	9,694
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed	–	–	–	–	552	50	3,782	133	–	4,517
Undeveloped	–	–	–	1	442	33	2,751	9	–	3,236
	–	–	–	1	994	83	6,533	142	–	7,753
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(11)	4	276	9	–	278
Improved recovery	–	–	–	–	16	–	–	–	–	16
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	22	–	219	–	–	241
Production[f]	–	–	–	–	(56)	(1)	(365)	(39)	–	(460)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	(29)	3	130	(29)	–	75
At 31 December[i j]										
Developed	–	–	–	–	528	86	3,834	100	–	4,548
Undeveloped	–	–	–	1	438	–	2,830	13	–	3,280
	–	–	–	1	965	86	6,663	112	–	7,828
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	280	225	2,525	2	1,116	536	3,782	715	735	9,916
Undeveloped	434	62	1,394	189	1,542	540	2,751	844	324	8,080
	714	287	3,919	191	2,658	1,076	6,533	1,559	1,059	17,996
At 31 December										
Developed	232	160	2,588	12	954	563	3,834	775	618	9,735
Undeveloped	398	26	1,191	164	1,576	403	2,830	881	319	7,788
	630	186	3,779	176	2,530	966	6,663	1,656	937	17,523

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.

[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[e] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.

[f] Includes 31 million barrels of oil equivalent of natural gas consumed in operations, 26 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities.

[g] Includes 456 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[i] Includes 54 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.

[j] Total proved reserves held as part of our equity interest in Rosneft is 6,702 million barrels of oil equivalent, comprising 1 million barrels of oil equivalent in Canada, 33 million barrels of oil equivalent in Venezuela, 5 million barrels of oil equivalent in Vietnam and 6,663 million barrels of oil equivalent in Russia.

Movements in estimated net proved reserves – continued

million barrels

Crude oil[a b]	Europe		North America		South America	Africa	Asia		Australasia	2013
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		Total
Subsidiaries										
At 1 January										
Developed	228	153	1,127	–	16	306	–	268	45	2,143
Undeveloped	426	73	818	195	20	236	–	137	34	1,938
	654	226	1,945	195	36	542	–	405	79	4,081
Changes attributable to										
Revisions of previous estimates	(79)	(15)	(111)	(7)	1	30	–	65	(5)	(121)
Improved recovery	11	–	33	–	1	2	–	65	–	112
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	2	–	–	–	–	39	3	44
Production	(21)	(11)	(108)	–	(7)	(79)	–	(52)	(8)	(285)
Sales of reserves-in-place	(31)	–	(1)	–	–	–	–	–	–	(32)
	(120)	(26)	(185)	(7)	(5)	(47)	–	117	(10)	(283)
At 31 December[d]										
Developed	160	147	1,007	–	15	316	–	320	49	2,013
Undeveloped	374	53	752	188	17	180	–	202	19	1,785
	534	200	1,760	188	31	495	–	522	69	3,798
Equity-accounted entities (BP share)[e f]										
At 1 January										
Developed	–	–	–	–	336	3	2,433	198	–	2,970
Undeveloped	–	–	–	–	347	2	1,943	13	–	2,305
	–	–	–	–	683	5	4,376	211	–	5,275
Changes attributable to										
Revisions of previous estimates	–	–	–	1	(14)	(1)	295	1	–	281
Improved recovery	–	–	–	–	27	–	–	–	–	27
Purchases of reserves-in-place	–	–	–	–	34	–	4,550	–	–	4,584
Discoveries and extensions	–	–	–	–	12	–	228	–	–	240
Production	–	–	–	–	(27)	–	(301)	(85)	–	(412)
Sales of reserves-in-place	–	–	–	–	(85)	–	(4,321)	–	–	(4,406)
	–	–	–	1	(53)	(1)	451	(84)	–	314
At 31 December[g]										
Developed	–	–	–	–	316	2	2,970	120	–	3,407
Undeveloped	–	–	–	1	314	2	1,858	7	–	2,182
	–	–	–	1	630	4	4,828	127	–	5,590
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	228	153	1,127	–	352	309	2,433	466	45	5,113
Undeveloped	426	73	818	195	367	239	1,943	150	34	4,243
	654	226	1,945	195	719	547	4,376	616	79	9,357
At 31 December										
Developed	160	147	1,007	–	331	317	2,970	440	49	5,421
Undeveloped	374	53	752	189	331	182	1,858	209	19	3,965
	534	200	1,760	189	661	499	4,828	649	69	9,388

[a] Crude oil includes condensate and bitumen. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 72 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Includes 8 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 23 million barrels of crude oil in respect of the 0.47% non-controlling interest in Rosneft.
[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 4,860 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 32 million barrels in Venezuela and 4,827 million barrels in Russia.

Movements in estimated net proved reserves – continued

million barrels

Natural gas liquids[a b]	Europe UK	Europe Rest of Europe	North America US	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2013 Total
Subsidiaries										
At 1 January										
Developed	14	17	316	–	6	6	–	–	7	366
Undeveloped	5	6	171	–	12	19	–	–	11	225
	19	23	487	–	18	25	–	–	18	591
Changes attributable to										
Revisions of previous estimates	1	(4)	(30)	–	29	(4)	–	–	(7)	(15)
Improved recovery	1	–	19	–	–	–	–	–	–	20
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	2	–	–	–	–	–	–	2
Production[c]	(1)	(1)	(24)	–	(4)	(1)	–	–	(1)	(33)
Sales of reserves-in-place	(5)	–	(10)	–	–	–	–	–	–	(15)
	(4)	(5)	(43)	–	25	(5)	–	–	(8)	(40)
At 31 December[d]										
Developed	9	16	290	–	14	4	–	–	8	342
Undeveloped	6	2	155	–	28	15	–	–	3	209
	15	18	444	–	43	20	–	–	10	551
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	–	–	–	–	3	9	59	–	–	71
Undeveloped	–	–	–	–	4	9	19	–	–	32
	–	–	–	–	7	18	78	–	–	103
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(7)	(2)	89	–	–	81
Improved recovery	–	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	–	–	–	–	29	–	–	29
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production	–	–	–	–	–	–	(2)	–	–	(3)
Sales of reserves-in-place	–	–	–	–	–	–	(78)	–	–	(78)
	–	–	–	–	(7)	(2)	38	–	–	29
At 31 December[f]										
Developed	–	–	–	–	–	8	94	–	–	103
Undeveloped	–	–	–	–	–	8	21	–	–	29
	–	–	–	–	–	16	115	–	–	131
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	14	17	316	–	9	15	59	–	7	437
Undeveloped	5	6	171	–	16	27	19	–	11	257
	19	23	487	–	25	43	78	–	18	693
At 31 December										
Developed	9	16	290	–	14	13	94	–	8	444
Undeveloped	6	2	155	–	28	23	21	–	3	238
	15	18	444	–	43	36	115	–	10	682

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Excludes NGLs from processing plants in which an interest is held of 5,500 barrels per day.
[d] Includes 13 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Total proved NGL reserves held as part of our equity interest in Rosneft is 115 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 115 million barrels in Russia.

Movements in estimated net proved reserves – continued

Total liquids[a b]	Europe UK	Europe Rest of Europe	North America US[c]	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	million barrels 2013 Total
Subsidiaries										
At 1 January										
Developed	242	170	1,444	–	22	312	–	268	52	2,509
Undeveloped	431	79	989	195	32	255	–	137	45	2,164
	673	249	2,433	195	54	567	–	405	96	4,673
Changes attributable to										
Revisions of previous estimates	(78)	(19)	(141)	(7)	30	26	–	65	(12)	(136)
Improved recovery	12	–	52	–	1	2	–	65	–	132
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	3	–	–	–	–	39	3	45
Production[d]	(22)	(13)	(132)	–	(11)	(80)	–	(52)	(9)	(319)
Sales of reserves-in-place	(36)	–	(12)	–	–	–	–	–	–	(48)
	(124)	(31)	(229)	(7)	20	(52)	–	117	(18)	(324)
At 31 December[e]										
Developed	169	163	1,297	–	29	320	–	320	57	2,354
Undeveloped	380	55	907	188	46	195	–	202	22	1,994
	549	217	2,204	188	74	515	–	523	78	4,348
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	–	–	–	–	339	12	2,492	198	–	3,041
Undeveloped	–	–	–	–	351	11	1,962	13	–	2,337
	–	–	–	–	691	23	4,453	211	–	5,378
Changes attributable to										
Revisions of previous estimates	–	–	–	1	(21)	(3)	384	1	–	362
Improved recovery	–	–	–	–	27	–	–	–	–	27
Purchases of reserves-in-place	–	–	–	–	34	–	4,579	–	–	4,613
Discoveries and extensions	–	–	–	–	11	–	228	–	–	239
Production	–	–	–	–	(27)	–	(302)	(85)	–	(414)
Sales of reserves-in-place	–	–	–	–	(85)	–	(4,399)	–	–	(4,485)
	–	–	–	1	(61)	(3)	490	(84)	–	343
At 31 December[g h]										
Developed	–	–	–	–	316	10	3,063	120	–	3,510
Undeveloped	–	–	–	1	314	10	1,879	7	–	2,210
	–	–	–	1	630	20	4,943	127	–	5,721
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	242	170	1,444	–	361	324	2,492	466	52	5,550
Undeveloped	431	79	989	195	384	266	1,962	150	45	4,501
	673	249	2,433	195	745	590	4,453	616	96	10,051
At 31 December										
Developed	169	163	1,297	–	345	331	3,063	440	57	5,865
Undeveloped	380	55	907	188	359	205	1,879	209	22	4,204
	549	217	2,204	189	704	535	4,943	650	78	10,069

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 72 million barrels upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Excludes NGLs from processing plants in which an interest is held of 5,500 barrels per day.
[e] Also includes 21 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] Includes 23 million barrels in respect of the non-controlling interest in Rosneft.
[h] Total proved liquid reserves held as part of our equity interest in Rosneft is 4,975 million barrels, comprising 1 million barrels in Canada, 32 million barrels in Venezuela, less than 1 million barrels in Vietnam and 4,943 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas[a b]										billion cubic feet 2013
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	1,038	340	8,245	4	3,588	1,139	–	926	3,282	18,562
Undeveloped	666	141	2,986	–	6,250	1,923	–	413	2,323	14,702
	1,704	481	11,231	4	9,838	3,062	–	1,339	5,605	33,264
Changes attributable to										
Revisions of previous estimates	(62)	(47)	(1,166)	10	62	(138)	–	2,148	(140)	667
Improved recovery	49	–	630	–	144	28	–	94	–	945
Purchases of reserves-in-place	9	–	–	–	–	–	–	–	–	9
Discoveries and extensions	–	–	39	–	–	55	–	1,875	511	2,480
Production[c]	(66)	(31)	(635)	(4)	(819)	(239)	–	(199)	(289)	(2,282)
Sales of reserves-in-place	(677)	–	(152)	–	–	–	–	(67)	–	(896)
	(747)	(78)	(1,284)	6	(613)	(294)	–	3,851	82	923
At 31 December[d]										
Developed	643	364	7,122	10	3,109	961	–	1,519	3,932	17,660
Undeveloped	314	39	2,825	–	6,116	1,807	–	3,671	1,755	16,527
	957	403	9,947	10	9,225	2,768	–	5,190	5,687	34,187
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	–	–	–	–	1,276	175	2,617	128	–	4,196
Undeveloped	–	–	–	–	904	164	1,759	18	–	2,845
	–	–	–	–	2,180	339	4,376	146	–	7,041
Changes attributable to										
Revisions of previous estimates	–	–	–	1	3	29	685	1	–	719
Improved recovery	–	–	–	–	64	–	–	3	–	67
Purchases of reserves-in-place	–	–	–	–	14	–	8,871	33	–	8,918
Discoveries and extensions	–	–	–	–	51	–	254	–	–	305
Production[c]	–	–	–	–	(163)	(3)	(292)	(23)	–	(481)
Sales of reserves-in-place	–	–	–	–	(38)	–	(4,669)	(74)	–	(4,781)
	–	–	–	1	(69)	26	4,849	(60)	–	4,747
At 31 December[f g]										
Developed	–	–	–	–	1,364	230	4,171	72	–	5,837
Undeveloped	–	–	–	1	747	135	5,054	14	–	5,951
	–	–	–	1	2,111	365	9,225	86	–	11,788
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	1,038	340	8,245	4	4,864	1,314	2,617	1,054	3,282	22,758
Undeveloped	666	141	2,986	–	7,154	2,087	1,759	431	2,323	17,547
	1,704	481	11,231	4	12,018	3,401	4,376	1,485	5,605	40,305
At 31 December										
Developed	643	364	7,122	10	4,473	1,191	4,171	1,591	3,932	23,497
Undeveloped	314	39	2,825	1	6,863	1,942	5,054	3,685	1,755	22,478
	957	403	9,947	11	11,336	3,133	9,225	5,276	5,687	45,975

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Includes 180 billion cubic feet of natural gas consumed in operations, 149 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities.
[d] Includes 2,685 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 41 billion cubic feet of natural gas in respect of the 0.44% non-controlling interest in Rosneft.
[g] Total proved gas reserves held as part of our equity interest in Rosneft is 9,271 billion cubic feet, comprising 1 billion cubic feet in Canada, 14 billion cubic feet in Venezuela, 31 billion cubic feet in Vietnam and 9,225 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

										million barrels of oil equivalent[c]
Total hydrocarbons[a b]										2013
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	421	229	2,865	1	640	508	–	427	618	5,709
Undeveloped	546	103	1,504	195	1,110	587	–	209	445	4,699
	967	332	4,369	196	1,750	1,095	–	636	1,063	10,408
Changes attributable to										
Revisions of previous estimates	(89)	(27)	(342)	(5)	41	3	–	435	(36)	(20)
Improved recovery	20	–	161	–	25	7	–	81	–	294
Purchases of reserves-in-place	2	–	–	–	–	–	–	–	–	2
Discoveries and extensions	–	–	10	–	–	9	–	363	91	473
Production[e f]	(34)	(18)	(241)	(1)	(152)	(121)	–	(86)	(59)	(712)
Sales of reserves-in-place	(152)	–	(38)	–	–	–	–	(12)	–	(202)
	(253)	(45)	(450)	(6)	(86)	(102)	–	781	(4)	(165)
At 31 December[g]										
Developed	280	225	2,525	2	564	486	–	582	735	5,399
Undeveloped	434	62	1,394	188	1,100	507	–	835	324	4,844
	714	287	3,919	190	1,664	993	–	1,417	1,059	10,243
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed	–	–	–	–	559	43	2,943	220	–	3,765
Undeveloped	–	–	–	–	508	39	2,265	15	–	2,827
	–	–	–	–	1,067	82	5,208	235	–	6,592
Changes attributable to										
Revisions of previous estimates	–	–	–	1	(20)	2	502	1	–	486
Improved recovery	–	–	–	–	38	–	–	1	–	39
Purchases of reserves-in-place	–	–	–	–	36	–	6,108	6	–	6,150
Discoveries and extensions	–	–	–	–	20	–	272	–	–	292
Production[f]	–	–	–	–	(55)	(1)	(353)	(88)	–	(497)
Sales of reserves-in-place	–	–	–	–	(92)	–	(5,204)	(13)	–	(5,309)
	–	–	–	1	(73)	1	1,325	(93)	–	1,161
At 31 December[i j]										
Developed	–	–	–	–	552	50	3,782	133	–	4,517
Undeveloped	–	–	–	1	442	33	2,751	9	–	3,236
	–	–	–	1	994	83	6,533	142	–	7,753
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	421	229	2,865	1	1,199	551	2,943	647	618	9,474
Undeveloped	546	103	1,504	195	1,618	626	2,265	224	445	7,526
	967	332	4,369	196	2,817	1,177	5,208	871	1,063	17,000
At 31 December										
Developed	280	225	2,525	2	1,116	536	3,782	715	735	9,916
Undeveloped	434	62	1,394	189	1,542	540	2,751	844	324	8,080
	714	287	3,919	191	2,658	1,076	6,533	1,559	1,059	17,996

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.
[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 72 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[e] Excludes NGLs from processing plants in which an interest is held of 5,500 barrels of oil equivalent per day.
[f] Includes 31 million barrels of oil equivalent of natural gas consumed in operations, 26 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities.
[g] Includes 484 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[i] Includes 30 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.
[j] Total proved reserves held as part of our equity interest in Rosneft is 6,574 million barrels of oil equivalent, comprising 1 million barrels of oil equivalent in Canada, 34 million barrels of oil equivalent in Venezuela, 5 million barrels of oil equivalent in Vietnam and 6,533 million barrels of oil equivalent in Russia.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves

The following tables set out the standardized measure of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group's estimated proved reserves. This information is prepared in compliance with FASB Oil and Gas Disclosures requirements.

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of average crude oil and natural gas prices and exchange rates from the previous 12 months. Furthermore, both proved reserves estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. BP cautions against relying on the information presented because of the highly arbitrary nature of the assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

$ million

	Europe		North America		South America	Africa	Asia		Australasia	Total 2015
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	27,500	7,800	98,100	7,200	20,100	32,800	–	65,200	32,000	290,700
Future production cost[b]	15,700	5,300	56,300	4,200	8,600	12,000	–	35,900	15,200	153,200
Future development cost[b]	4,700	700	18,800	1,700	7,000	8,100	–	18,200	4,500	63,700
Future taxation[c]	2,900	800	3,100	–	1,700	3,300	–	3,800	4,000	19,600
Future net cash flows	4,200	1,000	19,900	1,300	2,800	9,400	–	7,300	8,300	54,200
10% annual discount[d]	1,900	300	7,400	900	900	4,300	–	3,700	4,400	23,800
Standardized measure of discounted future net cash flows[e]	2,300	700	12,500	400	1,900	5,100	–	3,600	3,900	30,400
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	–	39,900	–	182,300	3,700	–	225,900
Future production cost[b]	–	–	–	–	20,200	–	101,200	2,200	–	123,600
Future development cost[b]	–	–	–	–	5,300	–	11,000	1,300	–	17,600
Future taxation[c]	–	–	–	–	3,900	–	12,400	100	–	16,400
Future net cash flows	–	–	–	–	10,500	–	57,700	100	–	68,300
10% annual discount[d]	–	–	–	–	6,700	–	33,800	–	–	40,500
Standardized measure of discounted future net cash flows[g h]	–	–	–	–	3,800	–	23,900	100	–	27,800
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	2,300	700	12,500	400	5,700	5,100	23,900	3,700	3,900	58,200

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

$ million

	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(27,900)	(7,300)	(35,200)
Development costs for the current year as estimated in previous year	15,000	4,500	19,500
Extensions, discoveries and improved recovery, less related costs	600	700	1,300
Net changes in prices and production cost	(100,400)	(24,700)	(125,100)
Revisions of previous reserves estimates	13,500	500	14,000
Net change in taxation	38,600	2,300	40,900
Future development costs	3,200	(100)	3,100
Net change in purchase and sales of reserves-in-place	(700)	300	(400)
Addition of 10% annual discount	8,000	4,700	12,700
Total change in the standardized measure during the year[i]	(50,100)	(19,100)	(69,200)

[a] The marker prices used were Brent $54.17/bbl, Henry Hub $2.59/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.
[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
[e] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $600 million.
[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[g] Non-controlling interests in Rosneft amounted to $93 million in Russia.
[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
[i] Total change in the standardized measure during the year includes the effect of exchange rate movements. Exchange rate effects arising from the translation of our share of Rosneft to US dollars are included within 'Net changes in prices and production cost'.

										$ million
										2014
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	54,400	14,900	216,600	11,000	35,300	55,800	–	90,300	54,800	533,100
Future production cost[b]	21,400	8,100	90,500	4,800	11,300	15,600	–	41,500	17,600	210,800
Future development cost[b]	7,300	1,400	24,500	1,600	8,000	9,600	–	23,000	5,700	81,100
Future taxation[c]	16,400	3,000	32,900	700	8,400	10,100	–	5,100	9,400	86,000
Future net cash flows	9,300	2,400	68,700	3,900	7,600	20,500	–	20,700	22,100	155,200
10% annual discount[d]	4,700	700	33,100	2,500	3,100	7,800	–	11,000	11,800	74,700
Standardized measure of discounted future net cash flows[e]	4,600	1,700	35,600	1,400	4,500	12,700	–	9,700	10,300	80,500
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	–	47,300	–	349,200	10,200	–	406,700
Future production cost[b]	–	–	–	–	22,300	–	200,000	7,800	–	230,100
Future development cost[b]	–	–	–	–	5,700	–	17,400	2,100	–	25,200
Future taxation[c]	–	–	–	–	6,700	–	24,200	100	–	31,000
Future net cash flows	–	–	–	–	12,600	–	107,600	200	–	120,400
10% annual discount[d]	–	–	–	–	8,000	–	65,500	–	–	73,500
Standardized measure of discounted future net cash flows[g h]	–	–	–	–	4,600	–	42,100	200	–	46,900
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	4,600	1,700	35,600	1,400	9,100	12,700	42,100	9,900	10,300	127,400

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

			$ million
	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(30,500)	(6,900)	(37,400)
Development costs for the current year as estimated in previous year	15,700	3,600	19,300
Extensions, discoveries and improved recovery, less related costs	1,900	1,500	3,400
Net changes in prices and production cost	(17,000)	10,500	(6,500)
Revisions of previous reserves estimates	1,200	2,000	3,200
Net change in taxation	17,300	(4,900)	12,400
Future development costs	(4,500)	(400)	(4,900)
Net change in purchase and sales of reserves-in-place	(700)	–	(700)
Addition of 10% annual discount	8,800	3,800	12,600
Total change in the standardized measure during the year[i]	(7,800)	9,200	1,400

[a] The marker prices used were Brent $101.27/bbl, Henry Hub $4.31/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.
[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
[e] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $1,400 million.
[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[g] Non-controlling interests in Rosneft amounted to $100 million in Russia.
[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
[i] Total change in the standardized measure during the year includes the effect of exchange rate movements. Exchange rate effects arising from the translation of our share of Rosneft to US dollars are included within 'Net changes in prices and production cost'.

	Europe		North America		South America	Africa	Asia		Australasia	Total
										$ million
										2013
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	66,200	26,300	234,500	9,400	40,000	67,500	–	89,000	57,600	590,500
Future production cost[b]	21,900	11,200	99,000	4,600	11,600	17,800	–	35,000	20,000	221,100
Future development cost[b]	6,500	2,000	27,700	2,000	7,600	10,900	–	23,700	6,900	87,300
Future taxation[c]	23,900	8,000	37,000	400	11,100	14,300	–	6,200	8,100	109,000
Future net cash flows	13,900	5,100	70,800	2,400	9,700	24,500	–	24,100	22,600	173,100
10% annual discount[d]	6,800	2,200	34,300	1,900	4,200	9,300	–	13,300	12,800	84,800
Standardized measure of discounted future net cash flows[e]	7,100	2,900	36,500	500	5,500	15,200	–	10,800	9,800	88,300
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	–	45,800	–	255,600	14,300	–	315,700
Future production cost[b]	–	–	–	–	22,500	–	139,000	11,800	–	173,300
Future development cost[b]	–	–	–	–	6,000	–	19,700	2,100	–	27,800
Future taxation[c]	–	–	–	–	5,900	–	15,200	100	–	21,200
Future net cash flows	–	–	–	–	11,400	–	81,700	300	–	93,400
10% annual discount[d]	–	–	–	–	6,900	–	48,700	100	–	55,700
Standardized measure of discounted future net cash flows[g h]	–	–	–	–	4,500	–	33,000	200	–	37,700
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	7,100	2,900	36,500	500	10,000	15,200	33,000	11,000	9,800	126,000

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
			$ million
Sales and transfers of oil and gas produced, net of production costs	(30,600)	(7,900)	(38,500)
Development costs for the current year as estimated in previous year	14,000	3,200	17,200
Extensions, discoveries and improved recovery, less related costs	1,900	2,000	3,900
Net changes in prices and production cost	(1,800)	(100)	(1,900)
Revisions of previous reserves estimates	(3,100)	(400)	(3,500)
Net change in taxation	12,900	3,400	16,300
Future development costs	(4,100)	(2,100)	(6,200)
Net change in purchase and sales of reserves-in-place	(3,500)	9,000	5,500
Addition of 10% annual discount	9,300	2,800	12,100
Total change in the standardized measure during the year[i]	(5,000)	9,900	4,900

[a] The marker prices used were Brent $108.02/bbl, Henry Hub $3.66/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.
[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
[e] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $1,700 million.
[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[g] Non-controlling interests in Rosneft amounted to $200 million in Russia.
[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
[i] Total change in the standardized measure during the year includes the effect of exchange rate movements.

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage. Figures include amounts attributable to assets held for sale.

Crude oil and natural gas production

The following table shows crude oil, natural gas liquids and natural gas production for the years ended 31 December 2015, 2014 and 2013.

Production for the year[a] [b]

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[c]	Rest of Asia		
Subsidiaries										
Crude oil[d]										thousand barrels per day
2015	**72**	**38**	**323**	**3**	**12**	**270**	**–**	**237**	**17**	**971**
2014	46	41	347	–	13	222	–	156	19	844
2013	58	31	305	–	17	217	–	141	21	789
Natural gas liquids										thousand barrels per day
2015	**7**	**5**	**56**	**–**	**11**	**7**	**–**	**1**	**3**	**88**
2014	2	5	63	–	12	5	–	–	3	91
2013	3	4	58	–	12	3	–	1	4	86
Natural gas[e]										million cubic feet per day
2015	**155**	**111**	**1,528**	**10**	**1,922**	**589**	**–**	**380**	**801**	**5,495**
2014	71	102	1,519	10	2,147	513	–	408	814	5,585
2013	157	80	1,539	11	2,221	561	–	490	784	5,845
Equity-accounted entities (BP share)										
Crude oil[d]										thousand barrels per day
2015	**–**	**–**	**–**	**–**	**68**	**–**	**809**	**97**	**–**	**974**
2014	–	–	–	–	65	–	816	98	–	979
2013	–	–	–	–	62	–	826	232	–	1,120
Natural gas liquids										thousand barrels per day
2015	**–**	**–**	**–**	**–**	**3**	**3**	**4**	**–**	**–**	**10**
2014	–	–	–	–	3	4	5	–	–	12
2013	–	–	–	–	3	5	11	–	–	19
Natural gas[e]										million cubic feet per day
2015	**–**	**–**	**–**	**–**	**435**	**–**	**1,195**	**21**	**–**	**1,651**
2014	–	–	–	–	402	–	1,084	28	–	1,515
2013	–	–	–	–	384	–	801	30	–	1,216

[a] Production excludes royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Amounts reported for Russia include BP's share of Rosneft worldwide activities, including insignificant amounts outside Russia.
[d] Crude oil includes condensate.
[e] Natural gas production excludes gas consumed in operations.

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the group and its equity-accounted entities had interests as at 31 December 2015. A 'gross' well or acre is one in which a whole or fractional working interest is owned, while the number of 'net' wells or acres is the sum of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves.

		Europe		North America		South America	Africa	Asia		Australasia	Total[b]
		UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Number of productive wells at 31 December 2015											
Oil wells[c]	– gross	**121**	**65**	**2,428**	**143**	**4,848**	**659**	**45,134**	**1,036**	**12**	**54,446**
	– net	**77**	**26**	**830**	**33**	**2,680**	**457**	**8,914**	**354**	**2**	**13,374**
Gas wells[d]	– gross	**63**	**5**	**22,760**	**309**	**821**	**144**	**791**	**860**	**73**	**25,826**
	– net	**27**	**1**	**9,492**	**153**	**303**	**62**	**156**	**320**	**14**	**10,529**
Oil and natural gas acreage at 31 December 2015											thousands of acres
Developed	– gross	**128**	**40**	**6,226**	**237**	**1,386**	**655**	**4,828**	**866**	**194**	**14,558**
	– net	**74**	**17**	**3,366**	**111**	**417**	**255**	**908**	**267**	**36**	**5,452**
Undeveloped[e]	– gross	**1,500**	**1,501**	**6,662**	**9,712**	**22,046**	**32,692**	**378,688**	**7,395**	**15,661**	**475,856**
	– net	**1,056**	**571**	**4,855**	**5,566**	**6,619**	**21,210**	**73,971**	**2,518**	**9,743**	**126,108**

[a] Based on information received from Rosneft as at 31 December 2015.
[b] Because of rounding some totals may not exactly agree with the sum of their component parts.
[c] Includes approximately 7,944 gross (1,582 net) multiple completion wells (more than one formation producing into the same well bore).
[d] Includes approximately 3,232 gross (1,534 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.
[e] Undeveloped acreage includes leases and concessions.

Operational and statistical information – continued

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	Europe		North America		South America	Africa	Asia		Australasia	Total[a]
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
2015										
Exploratory										
Productive	**–**	**–**	**4.0**	**–**	**1.1**	**2.6**	**4.5**	**–**	**–**	**12.2**
Dry	**–**	**–**	**–**	**–**	**0.4**	**1.0**	**–**	**–**	**0.2**	**1.6**
Development										
Productive	**1.6**	**0.4**	**235.6**	**–**	**143.1**	**20.7**	**91.4**	**51.2**	**0.9**	**544.7**
Dry	**–**	**–**	**–**	**–**	**2.3**	**1.3**	**–**	**–**	**–**	**3.5**
2014										
Exploratory										
Productive	2.9	–	5.3	–	3.7	0.7	5.3	0.6	–	18.5
Dry	0.5	–	7.9	–	1.4	1.6	–	1.4	0.2	13.0
Development										
Productive	3.1	1.8	294.1	1.5	100.5	13.8	76.2	46.3	–	537.3
Dry	–	0.8	–	0.1	3.9	1.0	–	0.4	0.4	6.6
2013										
Exploratory										
Productive	1.0	–	12.7	–	4.5	1.5	4.0	3.5	–	27.2
Dry	–	–	1.1	–	1.4	0.6	–	0.9	0.5	4.5
Development										
Productive	1.0	1.2	285.7	–	94.6	12.6	395.0	58.0	0.2	848.3
Dry	–	0.2	0.4	–	2.7	0.2	–	0.7	0.4	4.6

[a] Because of rounding, some totals may not exactly agree with the sum of their component parts.

Drilling and production activities in progress

The following table shows the number of exploratory and development oil and natural gas wells in the process of being drilled by the group and its equity-accounted entities as of 31 December 2015. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	Europe		North America		South America	Africa	Asia		Australasia	Total[a]
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2015										
Exploratory										
Gross	**1.0**	**–**	**11.0**	**–**	**–**	**4.0**	**–**	**–**	**–**	**16.0**
Net	**0.3**	**–**	**6.6**	**–**	**–**	**1.8**	**–**	**–**	**–**	**8.6**
Development										
Gross	**2.0**	**–**	**309.0**	**14.0**	**11.0**	**40.0**	**–**	**55.0**	**3.0**	**434.0**
Net	**1.3**	**–**	**109.0**	**7.0**	**6.2**	**18.9**	**–**	**19.8**	**0.5**	**162.7**

[a] Because of rounding, some totals may not exactly agree with the sum of their component parts.

Parent company financial statements of BP p.l.c.

Company balance sheet

At 31 December				$ million
	Note	**2015**	2014	2013
Fixed assets				
Investments	3	**139,241**	139,241	134,127
Defined benefit pension plan surplus	6	**2,516**	15	1,291
Total fixed assets		**141,757**	139,256	135,418
Current assets				
Debtors – amounts falling due within one year	4	**1,062**	7,159	21,550
Deferred tax asset	2	**–**	–	41
Cash at bank and in hand		**–**	31	6
		1,062	7,190	21,597
Creditors – amounts falling due within one year[a]	5	**212**	559	1,956
Net current assets		**850**	6,631	19,641
Total assets less current liabilities		**142,607**	145,887	155,059
Creditors – amounts falling due after more than one year[a]	5	**6,741**	6,961	6,953
Defined benefit pension plan deficit	6	**227**	599	271
Deferred tax liability	2	**877**	–	41
Net assets		**134,762**	138,327	147,794
Capital and reserves				
Called-up share capital	7	**5,049**	5,023	5,129
Share premium account		**10,234**	10,260	10,061
Capital redemption reserve		**1,413**	1,413	1,260
Merger reserve		**26,509**	26,509	26,509
Treasury shares		**(19,964)**	(20,719)	(20,971)
Foreign currency translation reserve		**–**	31	–
Profit and loss account		**111,521**	115,810	125,806
		134,762	138,327	147,794

[a] For 2014 and 2013 comparative balances there has been a reclassification from amounts due within one year to amounts due after one year as set out in Note 5.

The financial statements on pages 196-213 were approved and signed by the BP group chief executive on 4 March 2016 having been duly authorized to do so by the board of directors:

R W Dudley BP Group Chief Executive

The parent company financial statements of BP p.l.c. on pages 196-213 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Company cash flow statement

For the year ended 31 December		$ million
	2015	2014
Operating activities		
Profit before taxation	**653**	1,420
Adjustments to reconcile profit before taxation to net cash provided by operating activities		
Gain on sale of businesses and fixed assets	**(31)**	–
Interest receivable	**(108)**	(118)
Interest received	**13**	18
Finance cost	**36**	23
Net finance (income) expense relating to pensions and other post-retirement benefits	**20**	(50)
Share-based payments	**321**	379
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	**(263)**	(227)
Decrease in debtors	**6,185**	9,379
Decrease in creditors	**(197)**	(359)
Income taxes paid	**(1)**	(1)
Net cash provided by operating activities	**6,628**	10,464
Financing activities		
Net issue (repurchase) of shares	–	(4,589)
Dividends paid	**(6,659)**	(5,850)
Net cash used in financing activities	**(6,659)**	(10,439)
Increase (decrease) in cash	**(31)**	25
Cash at beginning of year	**31**	6
Cash at end of year	**–**	31

Company statement of changes in equity[a]

								$ million
	Share capital	**Share premium account**	**Capital redemption reserve**	**Merger reserve**	**Treasury shares**	**Foreign currency translation reserve**	**Profit and loss account**	**Total equity**
At 1 January 2015	**5,023**	**10,260**	**1,413**	**26,509**	**(20,719)**	**31**	**115,810**	**138,327**
Profit for the year	**–**	**–**	**–**	**–**	**–**	**–**	**571**	**571**
Currency translation differences	**–**	**–**	**–**	**–**	**–**	**(31)**	**–**	**(31)**
Actuarial gain on pensions (net of tax)	**–**	**–**	**–**	**–**	**–**	**–**	**1,894**	**1,894**
Total comprehensive income	**5,023**	**10,260**	**1,413**	**26,509**	**(20,719)**	**–**	**118,275**	**140,761**
Dividends	**26**	**(26)**	**–**	**–**	**–**	**–**	**(6,659)**	**(6,659)**
Share-based payments, net of tax	**–**	**–**	**–**	**–**	**755**	**–**	**(95)**	**660**
At 31 December 2015	**5,049**	**10,234**	**1,413**	**26,509**	**(19,964)**	**–**	**111,521**	**134,762**
At 1 January 2014	5,129	10,061	1,260	26,509	(20,971)	–	125,806	147,794
Profit for the year	–	–	–	–	–	–	1,378	1,378
Currency translation differences	–	–	–	–	–	31	–	31
Actuarial loss on pensions (net of tax)	–	–	–	–	–	–	(1,871)	(1,871)
Total comprehensive income	5,129	10,061	1,260	26,509	(20,971)	31	125,313	147,332
Dividends	41	(41)	–	–	–	–	(5,850)	(5,850)
Repurchases of ordinary share capital	(153)	–	153	–	–	–	(3,366)	(3,366)
Share-based payments, net of tax	6	240	–	–	252	–	(287)	211
At 31 December 2014	5,023	10,260	1,413	26,509	(20,719)	31	115,810	138,327

[a] See Note 8 for further information.

The parent company financial statements of BP p.l.c. on pages 196-213 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Notes on financial statements

1. Significant accounting policies, judgements, estimates and assumptions

Authorization of financial statements and statement of compliance with Financial Reporting Standard 101 Reduced Disclosure Framework (FRS 101)

The financial statements of BP p.l.c. for the year ended 31 December 2015 were approved and signed by the BP group chief executive on 4 March 2016 having been duly authorized to do so by the board of directors. The company meets the definition of a qualifying entity under Financial Reporting Standard 100 (FRS 100) issued by the Financial Reporting Council. Accordingly, these financial statements were prepared in accordance with Financial Reporting Standard 101 Reduced Disclosure Framework (FRS 101) and in accordance with the provisions of the Companies Act 2006.

There were no material measurement or recognition adjustments on the adoption of FRS 101. See Note 14 for further information.

Basis of preparation

These financial statements are prepared on a going concern basis and in accordance with the Companies Act 2006 and applicable UK accounting standards.

The financial statements have been prepared under the historical cost convention. Historical cost is generally based on the fair value of the consideration given in exchange for the assets.

As permitted by Section 408 of the Companies Act 2006, the profit and loss account of the company is not presented as part of these financial statements.

The financial statements are presented in US dollars and all values are rounded to the nearest million dollars ($ million).

Significant accounting policies: use of judgements, estimates and assumptions

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. Actual outcomes could differ from the estimates and assumptions used. The accounting judgements and estimates that could have a significant impact on the results of the company are set out in boxed text below, and should be read in conjunction with the information provided in the Notes on financial statements.

Investments

Investments in subsidiaries are recorded at cost. The company assesses investments for impairment whenever events or changes in circumstances indicate that the carrying value of an investment may not be recoverable. If any such indication of impairment exists, the company makes an estimate of its recoverable amount. Where the carrying amount of an investment exceeds its recoverable amount, the investment is considered impaired and is written down to its recoverable amount.

Significant estimate or judgement: investments

The recoverable amount, which is often the fair value less costs to sell, may be based upon discounted future cash flows. The assumptions underlying these calculations, such as the discount rate, future oil and gas prices, and other asset specific factors, are judgemental. Further information on the assumptions that are used in such calculations are included in Note 1 to the consolidated financial statements.

Foreign currency translation

The functional and presentation currency of the financial statements is US dollars. Transactions in foreign currencies are initially recorded in the functional currency by applying the rate of exchange ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the rate of exchange ruling at the balance sheet date. Any resulting exchange differences are included in the income statement.

Exchange adjustments arising when the opening net assets and the profits for the year retained by a non-US dollar functional currency branch are translated into US dollars are taken directly to reserves and reported in other comprehensive income. Income statement transactions are translated into US dollars using the average exchange rate for the reporting period.

Share-based payments

Equity-settled transactions

The cost of equity-settled transactions with employees of the company and other members of the BP group is measured by reference to the fair value at the date at which equity instruments are granted and is recognized as an expense over the vesting period, which ends on the date on which the employees become fully entitled to the award. A corresponding credit is recognized within equity. Fair value is determined by using an appropriate, widely used, valuation model. In valuing equity-settled transactions, no account is taken of any vesting conditions, other than conditions linked to the price of the shares of the company (market conditions). Non-vesting conditions, such as the condition that employees contribute to a savings-related plan, are taken into account in the grant-date fair value, and failure to meet a non-vesting condition, where this is within the control of the employee, is treated as a cancellation and any remaining unrecognized cost is expensed.

Cash-settled transactions

The cost of cash-settled transactions is recognized as an expense over the vesting period, measured by reference to the fair value of the corresponding liability which is recognized on the balance sheet. The liability is remeasured at each balance sheet date until settlement, with changes in fair value recognized in the income statement.

Pensions

The cost of providing benefits under the company's defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period to determine current service cost and to the current and prior periods to determine the present value of the defined benefit obligation. Past service costs, resulting from either a plan amendment or a curtailment (a reduction in future obligations as a result of a material reduction in the plan membership), are recognized immediately when the company becomes committed to a change.

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1. Significant accounting policies, judgements, estimates and assumptions – continued

Net interest expense relating to pensions and other post-retirement benefits, which is recognized in the income statement, represents the net change in present value of plan obligations and the value of plan assets resulting from the passage of time, and is determined by applying the discount rate to the present value of the benefit obligation at the start of the year, and to the fair value of plan assets at the start of the year, taking into account expected changes in the obligation or plan assets during the year.

Remeasurements of the defined benefit liability and asset, comprising actuarial gains and losses, and the return on plan assets (excluding amounts included in net interest described above) are recognized within other comprehensive income in the period in which they occur and are not subsequently reclassified to profit and loss.

The defined benefit pension plan surplus or deficit in the balance sheet comprises the total for each plan of the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds), less the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price. Defined benefit pension plan surpluses are only recognized to the extent they are recoverable.

Contributions to defined contribution plans are recognized in the income statement in the period in which they become payable.

Significant estimate or judgement: pensions and other post-retirement benefits

Accounting for pensions and other post-retirement benefits involves judgement about uncertain events, including estimated retirement dates, salary levels at retirement, mortality rates, determination of discount rates for measuring plan obligations and net interest expense and assumptions for inflation rates.

These assumptions are based on the environment in each country. The assumptions used may vary from year to year, which would affect future net income and net assets. Any differences between these assumptions and the actual outcome also affect future net income and net assets.

Pension and other post-retirement benefit assumptions are reviewed by management at the end of each year. The assumptions used are provided in Note 6.

Income taxes

Income tax expense represents the sum of current tax and deferred tax. Interest and penalties relating to income tax are also included in the income tax expense.

Income tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity, in which case the related tax is recognized in other comprehensive income or directly in equity.

Current tax is based on the taxable profit for the period. Taxable profit differs from net profit as reported in the income statement because it is determined in accordance with the rules established by the applicable taxation authorities. It therefore excludes items of income or expense that are taxable or deductible in other periods as well as items that are never taxable or deductible. The company's liability for current tax is calculated using tax rates and laws that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is provided, using the liability method, on temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes. Deferred tax liabilities are recognized for taxable temporary differences.

Deferred tax assets are only recognized to the extent that it is probable that they will be realized in the future.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date. Deferred tax assets and liabilities are not discounted.

Significant estimate or judgement: deferred tax

Management judgement is required to determine the amount of deferred tax assets that can be recognized, based upon the likely timing and level of future taxable profits.

Financial assets

All financial assets held by the company are classified as loans and receivables. Financial assets include cash and cash equivalents, other receivables, loans, and other investments. The company determines the classification of its financial assets at initial recognition. Financial assets are recognized initially at fair value, normally being the transaction price plus directly attributable transaction costs.

Loans and receivables

Loans and receivables are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired, as well as through the amortization process. This category of financial assets includes other receivables. Cash and cash equivalents are short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and have a maturity of three months or less from the date of acquisition.

Financial liabilities

All financial liabilities held by the company are classified as financial liabilities measured at amortized cost. Financial liabilities include other payables, accruals, and most items of finance debt. The company determines the classification of its financial liabilities at initial recognition.

Financial liabilities measured at amortized cost

All financial liabilities are initially recognized at fair value. For interest-bearing loans and borrowings this is the fair value of the proceeds received net of issue costs associated with the borrowing.

After initial recognition, financial liabilities are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs, and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized respectively in interest and other income and finance costs.

This category of financial liabilities includes other payables, financial guarantees and finance debt.

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2. Taxation

Tax charge included in total comprehensive income	2015	2014
		$ million
Deferred tax		
Origination and reversal of temporary differences in the current year	**877**	–
This comprises:		
Taxable temporary differences relating to pensions and other post-retirement benefits	**877**	(41)
Other taxable temporary differences	**–**	41

Deferred tax	2015	2014
Deferred tax liability		
Pensions and other post-retirement benefits	**877**	–
Net deferred tax liability	**877**	–
Analysis of movements during the year		
At 1 January	**–**	–
Charge for the year on ordinary activities	**81**	41
Charge (credit) for the year in other comprehensive income	**796**	(41)
At 31 December	**877**	–

At 31 December 2015, deferred tax assets of $65 million relating to other temporary differences and $8 million relating to pensions and other post-retirement benefits (2014 $95 million relating to other temporary differences and $25 million relating to pensions and other post-retirement benefits) were not recognized as it is not considered more likely than not that suitable taxable profits will be available in the company from which the future reversal of the underlying temporary differences can be deducted. It is anticipated that the reversal of these temporary differences will benefit other group companies in the future.

3. Investments

	Subsidiary undertakings	Associated undertakings		$ million
	Shares	Shares	Loans	Total
Cost				
At 1 January 2015	**139,313**	**2**	**–**	**139,315**
Additions	**2,800**	**–**	**–**	**2,800**
Disposals	**(2,800)**	**–**	**–**	**(2,800)**
At 31 December 2015	**139,313**	**2**	**–**	**139,315**
Amounts provided				
At 1 January 2015	**74**	**–**	**–**	**74**
At 31 December 2015	**74**	**–**	**–**	**74**
Cost				
At 1 January 2014	134,199	2	2	134,203
Additions	5,114	–	–	5,114
Disposals	–	–	(2)	(2)
At 31 December 2014	139,313	2	–	139,315
Amounts provided				
At 1 January 2014	74	–	2	76
Disposals	–	–	(2)	(2)
At 31 December 2014	74	–	–	74
At 31 December 2015	**139,239**	**2**	**–**	**139,241**
At 31 December 2014	139,239	2	–	139,241
At 31 December 2013	134,125	2	–	134,127

The more important subsidiary undertakings of the company at 31 December 2015 and the percentage holding of ordinary share capital (to the nearest whole number) are set out below. For a full list of significant holdings see Note 15.

Subsidiary undertakings	%	Country of incorporation	Principal activities
International			
BP Corporate Holdings	100	England & Wales	Investment holding
BP Global Investments	100	England & Wales	Investment holding
BP International	100	England & Wales	Integrated oil operations
Burmah Castrol	100	Scotland	Lubricants
Canada			
BP Holdings Canada	100	England & Wales	Investment holding
US			
BP Holdings North America	100	England & Wales	Investment holding

The carrying value of BP International Limited in the accounts of the company at 31 December 2015 was $70,425 million (2014 $67,625 million and 2013 $62,625 million).

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4. Debtors

			$ million
	2015	2014	2013
	Within 1 year	Within 1 year	Within 1 year
Group undertakings	**1,059**	7,159	21,550
Other debtors	**3**	–	–
	1,062	7,159	21,550

The company has a short-term receivable balance due from BP International Limited (2015 $757 million; 2014 $6,712 million) that arises primarily in relation to internal trading partner arrangements utilized to fund BP p.l.c.'s external dividend obligations. This balance, together with the carrying value of the guarantees as set out in Note 9, is included in the amounts due from group undertakings within one year.

BP p.l.c. received dividends of $1,618 million during the year (2014 $2,129 million), with the company also making dividend payments as set out in Note 9 to the consolidated financial statements.

5. Creditors

						$ million
		2015		2014		2013
	Within 1 year	**After 1 year**	Within 1 year	After 1 year	Within 1 year	After 1 year
Group undertakings	**100**	**6,708**	140	6,871	184	6,895
Accruals and deferred income	**81**	**33**	391	90	1,540	58
Other creditors	**31**	**–**	28	–	232	–
	212	**6,741**	559	6,961	1,956	6,953

Included in amounts due to group undertakings after one year is an interest-bearing payable balance of $4,236 million (2014 $4,236 million, 2013 $4,236 million) with BP International Limited, with interest being charged at a 1 year USD LIBOR rate and a maturity date of December 2021. Also included is an interest-bearing payable balance of $2,311 million with BP Finance plc, with interest being charged based on a 3 month USD LIBOR rate plus 55 basis points and a maturity date of April 2020. The comparative balances for 2014 and 2013 ($2,308 million and $2,311 million respectively) have been reclassified from amounts due within one year to amounts due after one year; this is in line with the underlying contractual terms and ensures a consistent presentation.

The maturity profile of the financial liabilities included in the balance sheet at 31 December is shown in the table below. These amounts are included within Creditors – amounts falling due after more than one year.

			$ million
	2015	2014	2013
Due within			
1 to 2 years	**75**	154	110
2 to 5 years	**85**	184	204
More than 5 years	**6,581**	6,623	6,639
	6,741	6,961	6,953

6. Pensions

The primary pension arrangement in the UK is a funded final salary pension plan under which retired employees draw the majority of their benefit as an annuity. This pension plan is governed by a corporate trustee whose board is composed of four member-nominated directors, four company-nominated directors, including an independent director, and an independent chairman nominated by the company. The trustee board is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as investment policies of the plan. The plan is closed to new joiners but remains open to ongoing accrual for current members. New joiners in the UK are eligible for membership of a defined contribution plan.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2015 the aggregate level of contributions was $754 million (2014 $713 million and 2013 $ 597 million). The aggregate level of contributions in 2016 is expected to be approximately $463 million, and includes contributions we expect to be required to make by law or under contractual agreements, as well as an allowance for discretionary funding.

For the primary UK plan there is a funding agreement between the company and the trustee. On an annual basis the latest funding position is reviewed and a schedule of contributions covering the next seven years is agreed. The funding agreement can be terminated unilaterally by either party with two years' notice. Contractually committed funding therefore represents nine years of future contributions, which amounted to $4,374 million at 31 December 2015, of which $1,437 million relates to past service. The surplus relating to the primary UK pension plan is recognized on the balance sheet on the basis that the company is entitled to a refund of any remaining assets once all members have left the plan.

The obligation and cost of providing the pension benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2015. The principal plans are subject to a formal actuarial valuation every three years in the UK. The most recent formal actuarial valuation of the main pension plan was as at 31 December 2014.

The material financial assumptions used for estimating the benefit obligations of the plans are set out below. The assumptions are reviewed by management at the end of each year, and are used to evaluate accrued pension and other post-retirement benefits at 31 December and pension expense for the following year.

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6. Pensions – continued

Financial assumptions used to determine benefit obligation			%
	2015	2014	2013
Discount rate for pension plan liabilities	**3.9**	3.6	4.6
Rate of increase in salaries	**4.4**	4.5	5.1
Rate of increase for pensions in payment	**3.0**	3.0	3.3
Rate of increase in deferred pensions	**3.0**	3.0	3.3
Inflation for pension plan liabilities	**3.0**	3.0	3.3

Financial assumptions used to determine benefit expense			%
	2015	2014	2013
Discount rate for pension plan service costs	**3.9**	4.8	4.4
Discount rate for pension plan other finance expense	**3.6**	4.6	4.4
Inflation for pension plan service costs	**3.1**	3.4	3.1

The discount rate assumption is based on third-party AA corporate bond indices and we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumption is based on the difference between the yields on index-linked and fixed-interest long-term government bonds. The inflation assumption is used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions.

The assumption for the rate of increase in salaries is based on our inflation assumption plus an allowance for expected long-term real salary growth. This includes an allowance for promotion-related salary growth.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. The mortality assumptions reflect best practice in the UK, and have been chosen with regard to the latest available published tables adjusted to reflect the experience of the plans and an extrapolation of past longevity improvements into the future. For the main pension plan the mortality assumptions are as follows:

Mortality assumptions			Years
	2015	2014	2013
Life expectancy at age 60 for a male currently aged 60	**28.5**	28.3	27.8
Life expectancy at age 60 for a male currently aged 40	**31.0**	30.9	30.7
Life expectancy at age 60 for a female currently aged 60	**29.5**	29.4	29.5
Life expectancy at age 60 for a female currently aged 40	**31.9**	31.8	32.2

The assets of the primary plan are held in a trust. The primary objective of the trust is to accumulate pools of assets sufficient to meet the obligations of the plan. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

A significant proportion of the assets are held in equities, owing to a higher expected level of return over the long term of such assets with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified.

For the primary UK pension plan there is an agreement with the trustee to reduce the proportion of plan assets held as equities and increase the proportion held as bonds over time, with a view to better matching the asset portfolio with the pension liabilities. During 2015, the plan switched 8% from equities to bonds.

In 2015, BP's primary plan in the UK adopted a more formal liability driven investment (LDI) approach for part of the portfolio, a form of investing designed to match the movement in pension plan assets with the impact of interest rate changes and inflation assumption changes on the projected benefit obligation.

The company's current asset allocation policy for the main plan is as follows:

Asset category	%
Total equity (including private equity)	62
Bonds/cash (including LDI)	31
Property/real estate	7

The amounts invested under the LDI programme as at 31 December 2015 were $329 million of government issued nominal bonds and $6,421 million of index-linked bonds. This is partly funded by short-term sale and repurchase agreements, proceeds from which are shown separately in the table below.

In addition, the primary UK plan entered into interest rate swaps in the year to offset the long-term fixed interest rate exposure for $2,651 million of the corporate bond portfolio. The $17 million fair value of the swaps as at 31 December 2015 is included in other assets in the table below.

The primary plan does not invest directly in either securities or property / real estate of the company or of any subsidiary.

The fair values of the various categories of assets held by the defined benefit plans at 31 December are presented in the table below, including the effects of derivative financial instruments. Movements in the fair value of plan assets during the year are shown in detail in the table on page 204.

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6. Pensions – continued

			$ million
	2015	2014	2013
Fair value of pension plan assets			
Listed equities – developed markets	**13,474**	16,190	17,341
– emerging markets	**2,305**	2,719	2,290
Private equity	**2,933**	2,983	2,907
Government issued nominal bonds[a]	**393**	642	549
Government issued index-linked bonds[a]	**6,425**	892	787
Corporate bonds[a]	**4,357**	4,687	4,427
Property[b]	**2,453**	2,403	2,200
Cash	**564**	1,145	855
Other	**110**	112	160
Debt (repurchase agreements) used to fund liability driven investments	**(1,791)**	–	–
	31,223	31,773	31,516

[a] Bonds held are denominated in sterling.
[b] Property held is all located in the United Kingdom.

			$ million
	2015	2014	2013
Analysis of the amount charged to profit before interest and taxation			
Current service cost[a]	**485**	494	497
Past service cost[b]	**12**	–	(22)
Operating charge relating to defined benefit plans	**497**	494	475
Payments to defined contribution plan	**31**	30	24
Total operating charge	**528**	524	499
Interest income on plan assets[c]	**1,124**	1,425	1,139
Interest on plan liabilities	**(1,144)**	(1,375)	(1,221)
Other finance income (expense)	**(20)**	50	(82)
Analysis of the amount recognized in other comprehensive income			
Actual return less interest income on pension plan assets	**315**	1,269	2,671
Change in financial assumptions underlying the present value of the plan liabilities	**2,054**	(3,181)	60
Change in demographic assumptions underlying the present value of plan liabilities	**–**	42	–
Experience gains and losses arising on the plan liabilities	**321**	(42)	41
Remeasurements recognized in other comprehensive income	**2,690**	(1,912)	2,772

[a] The costs of managing the fund's investments are treated as being part of the investment return, the costs of administering our pensions plan benefits are included in current service cost.
[b] Past service cost represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.
[c] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.

6. Pensions – continued

	$ million 2015	2014
Movements in benefit obligation during the year		
Benefit obligation at 1 January	**32,357**	30,496
Exchange adjustment	**(1,446)**	(1,989)
Operating charge relating to defined benefit plans	**497**	494
Interest cost	**1,144**	1,375
Contributions by plan participants[a]	**32**	39
Benefit payments (funded plans)[b]	**(1,269)**	(1,231)
Benefit payments (unfunded plans)[b]	**(6)**	(8)
Remeasurements	**(2,375)**	3,181
Benefit obligation at 31 December	**28,934**	32,357
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	**31,773**	31,516
Exchange adjustment	**(1,506)**	(1,958)
Interest income on plan assets[c]	**1,124**	1,425
Contributions by plan participants[a]	**32**	39
Contributions by employers (funded plans)	**754**	713
Benefit payments (funded plans)[b]	**(1,269)**	(1,231)
Remeasurements[c]	**315**	1,269
Fair value of plan assets at 31 December[d e]	**31,223**	31,773
Surplus (deficit) at 31 December	**2,289**	(584)
Represented by		
Asset recognized	**2,516**	15
Liability recognized	**(227)**	(599)
	2,289	(584)
The surplus (deficit) may be analysed between funded and unfunded plans as follows		
Funded	**2,506**	(310)
Unfunded	**(217)**	(274)
	2,289	(584)
The defined benefit obligation may be analysed between funded and unfunded plans as follows		
Funded	**(28,717)**	(32,083)
Unfunded	**(217)**	(274)
	(28,934)	(32,357)

[a] Most of the contributions made by plan participants were made under salary sacrifice.
[b] The benefit payments amount shown above comprises $1,253 million benefits plus $22 million of plan expenses incurred in the administration of the benefit.
[c] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.
[d] Reflects $31,030 million of assets held in the BP Pension Fund (2014 $31,600 million) and $147million held in the BP Global Pension Trust (2014 $134 million), with $37 million representing the company's share of Merchant Navy Officers Pension Fund (2014 $39 million) and $9 million of Merchant Navy Ratings Pension Fund (2014 $nil).
[e] The fair value of plan assets includes borrowings related to the LDI programme as described on page 202.

Sensitivity analysis

The discount rate, inflation, salary growth and the mortality assumptions all have a significant effect on the amounts reported. A one-percentage point change, in isolation, in certain assumptions as at 31 December 2015 for the company's plans would have had the effects shown in the table below. The effects shown for the expense in 2016 comprise the total of current service cost and net finance income or expense.

	$ million One percentage point Increase	Decrease
Discount rate[a]		
Effect on pension and other post-retirement benefit expense in 2016	**(328)**	307
Effect on pension and other post-retirement benefit obligation at 31 December 2015	**(4,651)**	6,027
Inflation rate[b]		
Effect on pension and other post-retirement benefit expense in 2016	**334**	(253)
Effect on pension and other post-retirement benefit obligation at 31 December 2015	**5,802**	(4,543)
Salary growth		
Effect on pension and other post-retirement benefit expense in 2016	**78**	(68)
Effect on pension and other post-retirement benefit obligation at 31 December 2015	**813**	(729)

[a] The amounts presented reflect that the discount rate is used to determine the asset interest income as well as the interest cost on the obligation.
[b] The amounts presented reflect the total impact of an inflation rate change on the assumptions for rate of increase in salaries, pensions in payment and deferred pensions.

One additional year of longevity in the mortality assumptions would increase the 2016 pension and other post-retirement benefit expense by $40 million and the pension and other post-retirement benefit obligation at 31 December 2015 by $861 million.

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6. Pensions – continued

Estimated future benefit payments and the weighted average duration of defined benefit obligations

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2025 and the weighted average duration of the defined benefit obligations at 31 December 2015 are as follows:

	$ million
Estimated future benefit payments	
2016	**1,059**
2017	**1,096**
2018	**1,148**
2019	**1,185**
2020	**1,208**
2021-2025	**6,562**
	Years
Weighted average duration	**18.2**

7. Called-up share capital

The allotted, called-up and fully paid share capital at 31 December was as follows:

	2015		2014		2013	
Issued	**Shares thousand**	**$ million**	Shares (thousand)	$ million	Shares (thousand)	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,005,961**	**5,002**	20,426,632	5,108	20,959,159	5,240
Issue of new shares for the scrip dividend programme	**102,810**	**26**	165,644	41	202,124	51
Issue of new shares for employee share-based payment plans[b]	**–**	**–**	25,598	6	18,203	5
Repurchase of ordinary share capital[c]	**–**	**–**	(611,913)	(153)	(752,854)	(188)
At 31 December	**20,108,771**	**5,028**	20,005,961	5,002	20,426,632	5,108
		5,049		5,023		5,129

[a] The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.
[b] Consideration received relating to the issue of new shares for employee share-based payment plans amounted to $207 million in 2014 and $116 million in 2013.
[c] There were no shares repurchased in 2015 (2014 shares were repurchased for a total consideration of $4,796 million, including transaction costs of $26 million and 2013 shares were repurchased for a total consideration of $5,493 million, including transaction costs of $30 million). All shares purchased were for cancellation.

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

Treasury shares[a]

	2015		2014		2013	
	Shares thousand	**Nominal value $ million**	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,811,297**	**453**	1,833,544	458	1,864,510	466
Purchases for settlement of employee share plans	**51,142**	**13**	49,559	12	38,766	9
Shares re-issued for employee share-based payment plans	**(106,112)**	**(27)**	(71,806)	(17)	(69,732)	(17)
At 31 December	**1,756,327**	**439**	1,811,297	453	1,833,544	458
Of which – shares held in treasury by BP	**1,727,763**	**432**	1,771,103	443	1,787,939	447
– shares held in ESOP trusts	**18,453**	**4**	34,169	9	32,748	8
– shares held by BP[b]	**10,111**	**3**	6,025	1	12,857	3

[a] See Note 8 for definition of treasury shares.
[b] Held by the company in the form of ADSs to meet the requirements of employee share-based payment plans in the US.

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury by BP during the year, representing 8.9% (2014 8.8% and 2013 8.7%) of the called-up ordinary share capital of the company.

During 2015, the movement in shares held in treasury by BP represented less than 0.2% (2014 less than 0.1% and 2013 less than 0.2%) of the ordinary share capital of the company.

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8. Capital and reserves

See statement of changes in equity for details of all reserves balances.

Share capital

The balance on the share capital account represents the aggregate nominal value of all ordinary and preference shares in issue, including treasury shares.

Share premium account

The balance on the share premium account represents the amounts received in excess of the nominal value of the ordinary and preference shares.

Capital redemption reserve

The balance on the capital redemption reserve represents the aggregate nominal value of all the ordinary shares repurchased and cancelled.

Merger reserve

The balance on the merger reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares.

Treasury shares

Treasury shares represent BP shares repurchased and available for specific and limited purposes.

For accounting purposes shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans are treated in the same manner as treasury shares and are therefore included in the financial statements as treasury shares. The ESOPs are funded by the company and have waived their rights to dividends in respect of such shares held for future awards. Until such time as the shares held by the ESOPs vest unconditionally to employees, the amount paid for those shares is shown as a reduction in shareholders' equity. Assets and liabilities of the ESOPs are recognized as assets and liabilities of the company.

Foreign currency translation reserve

The foreign currency translation reserve records exchange differences arising from the translation of the financial information of the foreign branch. Upon disposal of foreign operations, the related accumulated exchange differences are recycled to the income statement.

Profit and loss account

The balance held on this reserve is the accumulated retained profits of the company.

The profit and loss account reserve includes $24,107 million (2014 $24,107 million), the distribution of which is limited by statutory or other restrictions.

The accounts for the year ended 31 December 2015 do not reflect the dividend announced on 2 February 2016 and payable in March 2016; this will be treated as an appropriation of profit in the year ended 31 December 2016.

9. Contingent liabilities

The company has issued guarantees under which the maximum aggregate liabilities at 31 December 2015 were $51,775 million (2014 $51,463 million), the majority of which relate to finance debt of subsidiaries. The carrying value of the guarantees at 31 December 2015 was $211 million (2014 $417 million). The guarantee fee income recognized within profit for the year ending 31 December 2015 was $94 million (2014 $100 million). The company has also issued uncapped indemnities and guarantees, including a guarantee of subsidiaries' liabilities under the Plaintiffs' Steering Committee settlement agreement relating to the Gulf of Mexico oil spill, and in relation to potential losses arising from environmental incidents involving ships leased and operated by a subsidiary.

10. Capital management

The company defines capital as total equity (which is the company's net asset value). The company maintains its financial framework to support the pursuit of value growth for shareholders, while ensuring a secure financial base. The BP group aims to maintain the net debt ratio, that is, the ratio of net debt to net debt plus equity, with some flexibility, at around 20%.

11. Share-based payments

Effect of share-based payment transactions on the company's result and financial position

		$ million
	2015	2014
Total expense recognized for equity-settled share-based payment transactions	**759**	770
Total credit recognized for cash-settled share-based payment transactions	**(50)**	(81)
Total expense recognized for share-based payment transactions	**709**	689
Closing balance of liability for cash-settled share-based payment transactions	**32**	108
Total intrinsic value for vested cash-settled share-based payments	**–**	54

Additional information on the company's share-based payment plans is provided in Note 10 to the consolidated financial statements.

12. Auditor's remuneration

Note 35 to the consolidated financial statements provides details of the remuneration of the company's auditor on a BP group basis.

13. Directors' remuneration

		$ million
Remuneration of directors	**2015**	2014
Total for all directors		
Emoluments	**10**	14
Amounts awarded under incentive schemes[a]	**14**	10
Total	**24**	24

[a] Excludes amounts relating to past directors.

The parent company financial statements of BP p.l.c. on pages 196-213 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

13. Directors' remuneration – continued

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus cash bonuses awarded for the year. There was no compensation for loss of office in 2015 (2014 $nil).

14. Explanation of transition to FRS 101

For all periods up to and including the year ended 31 December 2014, the company prepared its financial statements in accordance with United Kingdom generally accepted accounting practice (UK GAAP). These financial statements, for the year ended 31 December 2015, are the first the company has prepared in accordance with FRS 101.

Comparative information included in these financial statements has also been prepared in accordance with FRS 101 and the significant accounting policies described in Note 1.

On transition to FRS 101, the company has applied the requirements of paragraphs 6 – 33 of IFRS 1 'First-time adoption of International Financial Reporting Standards' (IFRS 1).

Exemptions applied

IFRS 1 allows first-time adopters certain exemptions from the general requirements to apply IFRS. The company has taken advantage of the following exemptions:
(a) business combinations (paragraphs C1 – C5);
(b) share-based payment transactions (paragraphs D2 and D3);
(c) cumulative translation differences (paragraphs D12 and D13).

In preparing these financial statements, the company has started from an opening balance sheet as at 1 January 2014, the company's date of transition to FRS 101, and made those changes in accounting policies and other restatements required for the first time adoption of FRS 101.

Pensions

Under previous UK GAAP the interest cost was determined by applying the discount rate to the opening present value of the defined benefit obligation and the changes in the defined benefit obligation during the year. The interest income on the expected return on plan assets was based on an assessment made at the beginning of the year of the long-term market returns on plan assets. Under IAS 19 net interest is calculated by applying the discount rate to the net defined liability or asset. As a result of transition to FRS 101, net interest for the year ended 31 December 2014 was $722 million higher than had been recognized under previous UK GAAP (2013 $664 million), with a corresponding reduction in remeasurement gains recognized in other comprehensive income.

The parent company financial statements of BP p.l.c. on pages 196-213 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

15. Related undertakings of the group

In accordance with Section 409 of the Companies Act 2006, a full list of related undertakings, the country of incorporation and the percentage of share capital owned as at 31 December 2015 is disclosed below.

Unless otherwise stated, the share capital disclosed comprises ordinary shares or common stock (or local equivalent thereof) which are indirectly held by BP p.l.c.

Subsidiary undertakings are controlled by the group and their results are fully consolidated in the group's financial statements.

The percentage of share capital owned by the group is 100% unless otherwise noted below.

Subsidiaries

200 PS Overseas Holdings Inc. (United States)
4321 North 800 West LLC (United States)
563916 Alberta Ltd. (Canada, 99.90%)
ACP (Malaysia), Inc. (United States)
Actomat B.V. (Netherlands)
Advance Petroleum Holdings Pty Ltd (Australia)
Advance Petroleum Pty Ltd (Australia)
AE Cedar Creek Holdings LLC (United States)
AE Goshen II Holdings LLC (United States)
AE Goshen II Wind Farm LLC (United States)
AE Power Services LLC (United States)
AE Wind PartsCo LLC (United States)
Air BP Albania SHA (Albania)
Air BP Brasil Ltda. (Brazil)
Air BP Canada LLC (United States)
Air BP Croatia d.o.o. (Croatia)
Air BP Denmark ApS (Denmark)
Air BP Finland Oy (Finland)
Air BP Limited (United Kingdom)
Air BP Norway AS (Norway)
Air BP Sales Romania S.R.L. (Romania)
Air BP Sweden AB (Sweden)
Air Refuel Pty Ltd (Australia)
Alexander Duckham & Co.,Limited (United Kingdom)
Alexis Wind Farm LLC (United States)
Allgreen Pty Ltd (Australia)
AM/PM International Inc. (United States)
American Oil Company (United States)
Amoco (Fiddich) Limited (United Kingdom)
Amoco (U.K.) Exploration Company, LLC (United States)
Amoco Angola B.V. (Netherlands)
Amoco Austria Petroleum Company (United States)
Amoco Bolivia Petroleum Company (United States)
Amoco Bolivia Services Company Inc. (Virgin Islands, British)
Amoco Brazil, Inc. (United States)
Amoco Canada International Holdings B.V. (Netherlands)
Amoco Capline Pipeline Company (United States)
Amoco Caspian Sea Petroleum Company (United States)
Amoco Chemical (Europe) S.A. (United States)
Amoco Chemical Holding B.V. (Netherlands)[a]
Amoco Chemical U.K. Limited (in liquidation) (United Kingdom)
Amoco Chemicals (FSC) B.V. (Netherlands)
Amoco CNG (Trinidad) Limited (Trinidad and Tobago)
Amoco Cypress Pipeline Company (United States)
Amoco Destin Pipeline Company (United States)
Amoco Endicott Pipeline Company (United States)
Amoco Environmental Services Company (United States)
Amoco Exploration Holdings B.V. (Netherlands)
Amoco Fabrics (U.K.) Limited (in liquidation) (United Kingdom)
Amoco Fabrics and Fibers Ltd. (Canada)
Amoco Guatemala Petroleum Company (United States)[b]
Amoco Inam Petroleum Company B.V. (Netherlands)
Amoco International Finance Corporation (United States)
Amoco International Petroleum Company (United States)
Amoco Kazakhstan (CPC) Inc. (United States)
Amoco Leasing Corporation (United States)
Amoco Louisiana Fractionator Company (United States)
Amoco Main Pass Gathering Company (United States)
Amoco Marketing Environmental Services Company (United States)
Amoco MB Fractionation Company (United States)
Amoco MBF Company (United States)
Amoco Netherlands Petroleum Company (United States)
Amoco Nigeria Exploration Company Limited (Nigeria)[a]
Amoco Nigeria Oil Company Limited (Nigeria)[a]
Amoco Nigeria Petroleum Company (United States)
Amoco Nigeria Petroleum Company Limited (Nigeria)
Amoco Norway Oil Company (United States)
Amoco Oil Holding Company (United States)
Amoco Olefins Corporation (United States)
Amoco Overseas Exploration Company (United States)
Amoco Pipeline Asset Company (United States)
Amoco Pipeline Holding Company (United States)
Amoco Properties Incorporated (United States)
Amoco Realty Company (United States)
Amoco Remediation Management Services Corporation (United States)
Amoco Research Operating Company (United States)
Amoco Rio Grande Pipeline Company (United States)
Amoco Somalia Petroleum Company (United States)
Amoco Sulfur Recovery Company (United States)
Amoco Tax Leasing X Corporation (United States)
Amoco Trinidad Gas B.V. (Netherlands)
Amoco Tri-States NGL Pipeline Company (United States)
Amoco U.K. Petroleum Limited (United Kingdom)
AmProp Finance Company (United States)
Amprop Illinois I Ltd. Partnership (United States)[c]
Amprop, Inc. (United States)
Anaconda Arizona, Inc. (United States)
Aral Aktiengesellschaft (Germany)
Aral Luxembourg S.A. (Luxembourg)
Aral Mineralölvertrieb GmbH (Germany)
Aral Services Luxembourg Sarl (Luxembourg)
Aral Tankstellen Services Sarl (Luxembourg)
Aral Vertrieb GmbH (Germany)
ARCO British International, Inc. (United States)
ARCO British Limited, LLC (United States)
ARCO Coal Australia Inc. (United States)
Arco do Brasil Ltda. (Brazil)
ARCO El-Djazair Holdings Inc. (United States)
ARCO El-Djazair LLC (United States)[d]
ARCO Environmental Remediation, L.L.C. (United States)
ARCO Exploration, Inc. (United States)
ARCO Gaviota Company (United States)
ARCO Ghadames Inc. (United States)
ARCO International Investments Inc. (United States)
ARCO International Services Inc. (United States)
ARCO Material Supply Company (United States)
ARCO Midcon LLC (United States)
ARCO Neftegaz Holdings, Inc. (United States)
ARCO Oil Company Nigeria Unlimited (Nigeria)[d]
ARCO Oman Inc. (Bahamas)
ARCO Products Company (United States)
ARCO Resources Limited (Australia)
ARCO Terminal Services Corporation (United States)
ARCO Trinidad Exploration and Production Company Limited (Bahamas)
ARCO Unimar Holdings LLC (United States)
Aspac Lubricants (Malaysia) Sdn. Bhd. (Malaysia, 63.03%)
Atlantic 2/3 UK Holdings Limited (United Kingdom)
Atlantic Richfield Company (United States)[e]
Auwahi Wind Energy Holdings LLC (United States)[d]
B.V. Petrotank (Netherlands)
Bahia de Bizkaia Electridad, S.L. (Spain, 75.00%)
Baltimore Ennis Land Company, Inc. (United States)
Barrington Amsterdam Terminal B.V (Netherlands)
Black Lake Pipe Line Company (United States)
BP - Castrol (Thailand) Limited (Thailand, 57.56%)
BP (Abu Dhabi) Limited (United Kingdom)
BP (Barbados) Holding SRL (Barbados)
BP (Barbican) Limited (United Kingdom)[f]
BP (China) Holdings Limited (China)
BP (China) Industrial Lubricants Limited (China)
BP (Gibraltar) Limited (United Kingdom)[g]
BP (Indian Agencies) Limited (United Kingdom)[f]
BP (Shanghai) Trading Limited (China)
BP Africa Limited (United Kingdom)[f]
BP Akaryakit Ortakligi (Turkey, 70.00%)[c]
BP Alaska LNG LLC (United States)
BP Alternative Energy Holdings Limited (United Kingdom)
BP Alternative Energy International Limited (United Kingdom)
BP Alternative Energy North America Inc. (United States)
BP America Chembel Holding LLC (United States)
BP America Chemicals Company (United States)
BP America Foreign Investments Inc. (United States)
BP America Inc. (United States)[h]
BP America Limited (United Kingdom)
BP America Production Company (United States)
BP AMI Leasing, Inc. (United States)
BP Amoco Chemical Company (United States)
BP Amoco Chemical Holding Company (United States)
BP Amoco Chemical Indonesia Limited (United States)
BP Amoco Chemical Malaysia Holding Company (United States)
BP Amoco Chemical Singapore Holding Company (United States)
BP Amoco Exploration (Faroes) Limited (United Kingdom)

The parent company financial statements of BP p.l.c. on pages 196-213 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

15. Related undertakings of the group – continued

BP Amoco Exploration (In Amenas) Limited (United Kingdom)
BP Amoco Neighborhood Development Corporation (United States)
BP Angola (Block 18) B.V. (Netherlands)
BP Argentina Exploration Company (United States)
BP Aromatics Holdings Limited (United Kingdom)
BP Aromatics Limited (United Kingdom)
BP Aromatics Limited N.V. (Belgium)
BP Asia Limited (Hong Kong)
BP Asia Pacific (Malaysia) Sdn. Bhd. (Malaysia)
BP Asia Pacific Holdings Limited (United Kingdom)
BP Asia Pacific Pte Ltd (Singapore)[f]
BP Australia Capital Markets Limited (Australia)
BP Australia Employee Share Plan Proprietary Limited (Australia)
BP Australia Group Pty Ltd (Australia)[a]
BP Australia Investments Pty Ltd (Australia)
BP Australia Nominees Proprietary Limited (Australia)
BP Australia Pty Ltd (Australia)
BP Australia Shipping Pty Ltd (Australia)[j]
BP Australia Swaps Management Limited (United Kingdom)
BP Aviation A/S (Denmark)
BP Benevolent Fund Trustees Limited (United Kingdom)[f]
BP Berau Ltd. (United States)
BP Biocombustíveis S.A. (Brazil, 99.99%)
BP Bioenergia Campina Verde Ltda. (Brazil, 99.99%)[d]
BP Bioenergia Ituiutaba Ltda. (Brazil, 99.99%)[d]
BP Bioenergia Itumbiara S.A. (Brazil, 99.99%)
BP Bioenergia Tropical S.A. (Brazil, 99.97%)
BP Biofuels Advanced Technology Inc. (United States)
BP Biofuels Brazil Investments Limited (United Kingdom)
BP Biofuels Louisiana LLC (United States)
BP Biofuels North America LLC (United States)
BP Biofuels Trading Comércio, Importação e Exportação Ltda. (Brazil, 99.99%)
BP Biofuels UK Limited (United Kingdom)
BP Bomberai Ltd. (United States)
BP Brasil Investimentos Ltda (Brazil)
BP Brasil Ltda. (Brazil)
BP Brazil Tracking L.L.C. (United States)
BP Bulwer Island Pty Ltd (Australia)
BP Business Service Centre Asia Sdn Bhd (Malaysia)
BP Business Service Centre KFT (Hungary)[d]
BP Canada Energy Group ULC (Canada)
BP Canada Energy Marketing Corp. (United States)
BP Canada International Holdings B.V. (Netherlands)
BP Canada Investments Inc. (United States)
BP Capellen Sarl (Luxembourg)
BP Capital Euro V.O.F. (Belgium)
BP Capital Markets America Inc. (United States)
BP Capital Markets p.l.c. (United Kingdom)
BP Caplux S.A. (Luxembourg)
BP Car Finance Limited (United Kingdom)[f]
BP Caribbean Company (United States)
BP Castrol KK (Japan, 65.65%)
BP Castrol Lubricants (Malaysia) Sdn. Bhd. (Malaysia, 63.03%)
BP Chembel N.V. (Belgium)
BP Chemical US Sales Company (United States)
BP Chemicals (Korea) Limited (United Kingdom)
BP Chemicals East China Investments Limited (United Kingdom)
BP Chemicals France Holding (France)
BP Chemicals Investments Limited (United Kingdom)
BP Chemicals Limited (United Kingdom)
BP Chemicals Trading Limited (United Kingdom)
BP Chile Petrolera Limitada (Chile)
BP China Exploration and Production Company (United States)
BP China Limited (United Kingdom)[f]
BP Company North America Inc. (United States)[j]
BP Containment Response Limited (United Kingdom)
BP Containment Response System Holdings LLC (United States)
BP Continental Holdings Limited (United Kingdom)
BP Corporate Holdings Limited (United Kingdom)[f]
BP Corporation North America Inc. (United States)
BP Danmark A/S (Denmark)
BP Developments Australia Pty. Ltd. (Australia)
BP Dogal Gaz Ticaret Anonim Sirketi (Turkey)
BP East Kalimantan CBM Limited (United Kingdom)
BP East Kalimantan Limited (Bahamas)
BP Eastern Mediterranean Limited (United Kingdom)[f]
BP Egypt Company (United States)
BP Egypt East Delta Marine Corporation (Virgin Islands, British)
BP Egypt East Tanka B.V. (Netherlands)
BP Egypt Production B.V. (Netherlands)
BP Egypt Ras El Barr B.V. (Netherlands)
BP Egypt West Mediterranean (Block B) B.V. (Netherlands)
BP Energy Asia Pte. Limited (Singapore)
BP Energy Colombia Limited (United Kingdom)
BP Energy Company (United States)
BP Energy do Brasil Ltda. (Brazil)
BP Energy Europe Limited (United Kingdom)
BP Espana, S.A. Unipersonal (Spain)
BP Europa SE (Germany)[k, l]
BP Exploracion de Venezuela S.A. (Venezuela, Bolivarian Republic of)
BP Exploration & Production Inc. (United States)[m]
BP Exploration (Alaska) Inc. (United States)
BP Exploration (Algeria) Limited (United Kingdom)
BP Exploration (Alpha) Limited (United Kingdom)
BP Exploration (Angola) Limited (United Kingdom)
BP Exploration (Azerbaijan) Limited (United Kingdom)
BP Exploration (Canada) Limited (United Kingdom)
BP Exploration (Caspian Sea) Limited (United Kingdom)
BP Exploration (Delta) Limited (United Kingdom)
BP Exploration (El Djazair) Limited (Bahamas)
BP Exploration (Epsilon) Limited (United Kingdom)
BP Exploration (Finance) Limited (United Kingdom)
BP Exploration (Greenland) Limited (United Kingdom)
BP Exploration (Morocco) Limited (United Kingdom)
BP Exploration (Namibia) Limited (United Kingdom)
BP Exploration (Nigeria Finance) Limited (United Kingdom)
BP Exploration (Nigeria) Limited (Nigeria)
BP Exploration (Shafag-Asiman) Limited (United Kingdom)
BP Exploration (Shah Deniz) Limited (United Kingdom)
BP Exploration (South Atlantic) Limited (United Kingdom)
BP Exploration (Vietnam) Limited (United Kingdom)
BP Exploration (Xazar) PTE. LTD. (Singapore)
BP Exploration Angola (Kwanza Benguela) Limited (United Kingdom)
BP Exploration Australia Pty Ltd (Australia)
BP Exploration Beta Limited (United Kingdom)
BP Exploration China Limited (United Kingdom)
BP Exploration Company (Middle East) Limited (United Kingdom)
BP Exploration Company Limited (United Kingdom)
BP Exploration do Brasil Ltda (Brazil)
BP Exploration Indonesia Limited (United Kingdom)
BP Exploration Libya Limited (United Kingdom)
BP Exploration Mexico Limited (United Kingdom)
BP Exploration Mexico, S.A. de C.V. (Mexico)
BP Exploration North Africa Limited (United Kingdom)
BP Exploration Operating Company Limited (United Kingdom)
BP Exploration Orinoco Limited (United Kingdom)
BP Exploration Personnel Company Limited (United Kingdom)
BP Exploration Services Limited (In Liquidation) (United Kingdom)
BP Exploration Venezuela Limited (In Liquidation) (United Kingdom)
BP Express Shopping Limited (United Kingdom)
BP Finance Australia Pty Ltd (Australia)
BP Finance p.l.c. (United Kingdom)
BP Foundation Incorporated (United States)
BP France (France)
BP Fuels & Lubricants AS (Norway)
BP Fuels Deutschland GmbH (Germany)
BP Gas Europe, S.A.U. (Spain)
BP Gas Marketing Limited (United Kingdom)
BP Gas Supply (Angola) LLC (United States)
BP Gaz Anonim Sirketi (Turkey)
BP Gelsenkirchen GmbH (Germany)
BP Ghana Limited (Ghana)
BP Global Investments Limited (United Kingdom)[f]
BP Global Investments Salalah & Co LLC (Oman)[d]
BP Global West Africa Limited (Nigeria)
BP Greece Limited (United Kingdom)
BP Guangdong Limited (China, 90.00%)
BP High Density Polyethylene France - BP HDPE (France)
BP Holdings (Thailand) Limited (Thailand, 81.01%)
BP Holdings B.V. (Netherlands)
BP Holdings Canada Limited (United Kingdom)[f]
BP Holdings International B.V. (Netherlands)
BP Holdings North America Limited (United Kingdom)[f]
BP Hong Kong Limited (Hong Kong)
BP India Services Private Limited (India)
BP Indonesia Investment Limited (United Kingdom)
BP International Limited (United Kingdom)[f]
BP International Services Company (United States)
BP Investment Management Limited (United Kingdom)
BP Investments Asia Limited (United Kingdom)
BP Iran Limited (United Kingdom)
BP Iraq N.V. (Belgium)
BP Italia SpA (Italy)
BP Japan K.K. (Japan)
BP Kapuas I Limited (United Kingdom)
BP Kapuas II Limited (United Kingdom)
BP Kapuas III Limited (United Kingdom)
BP Korea Limited (Korea, Republic of)
BP Kuwait Limited (United Kingdom)
BP Latin America LLC (United States)
BP Lesotho (Pty) Limited (Lesotho)[f]
BP Lingen GmbH (Germany)
BP LNG Shipping Limited (Bermuda)
BP Lubes Marketing GmbH (Germany)
BP Lubricants KK (Japan, 65.65%)
BP Lubricants USA Inc. (United States)
BP Luxembourg S.A. (Luxembourg)
BP Malaysia Holdings Sdn. Bhd. (Malaysia, 70.00%)
BP Malta Limited (Malta)[f]
BP Management International B.V. (Netherlands)

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15. Related undertakings of the group – continued

BP Management Netherlands B.V. (Netherlands)
BP Marine Limited (United Kingdom)
BP Maritime Services (Isle of Man) Limited (Isle of Man)
BP Maritime Services (Singapore) Pte. Limited (Singapore)
BP Marketing Egypt LLC (Egypt)
BP Mauritius Limited (Mauritius)
BP Middle East Enterprises Corporation (Virgin Islands, British)
BP Middle East Limited (United Kingdom)[f]
BP Middle East LLC (United Arab Emirates)
BP Mocambique Limitada (Mozambique)
BP Mocambique Limited (United Kingdom)
BP Muturi Holdings B.V. (Netherlands)
BP Nederland Holdings BV (Netherlands)
BP Netherlands Exploration Holding B.V. (Netherlands)
BP New Zealand Holdings Limited (New Zealand)
BP New Zealand Share Scheme Limited (New Zealand)
BP Norge AS (Norway)
BP Nutrition Inc. (United States)
BP Offshore Gathering Systems Inc. (United States)
BP Offshore Pipelines Inc. (United States)
BP Offshore Response Company LLC (United States)
BP Oil (Thailand) Limited (Thailand)[n]
BP Oil and Chemicals International Philippines Inc. (Philippines)
BP Oil Australia Pty Ltd (Australia)
BP Oil Espana, S.A. Unipersonal (Spain)
BP Oil Hellenic S.A. (Greece)
BP Oil International Limited (United Kingdom)
BP Oil Kent Refinery Limited (in liquidation) (United Kingdom)
BP Oil Llandarcy Refinery Limited (United Kingdom)
BP Oil Logistics UK Limited (United Kingdom)
BP Oil Marketing GmbH (Germany)
BP Oil New Zealand Limited (New Zealand)
BP Oil Pipeline Company (United States)
BP Oil Shipping Company, USA (United States)
BP Oil UK Limited (United Kingdom)
BP Oil Venezuela Limited (United Kingdom)
BP Oil Vietnam Limited (United Kingdom)
BP Oil Yemen Limited (United Kingdom)
BP Olex Fanal Mineralol GmbH (Germany)
BP Pacific Investments Ltd (New Zealand)
BP Pakistan (Badin) Inc. (United States)
BP Pakistan Exploration and Production, Inc. (United States)
BP Pension Trustees Limited (United Kingdom)[f]
BP Pensions (Overseas) Limited (Guernsey)[f]
BP Pensions Limited (United Kingdom)[f]
BP Petrochemicals India Investments Limited (United Kingdom)
BP Petroleo y Gas, S.A. (Venezuela, Bolivarian Republic of)
BP Petrolleri Anonim Sirketi (Turkey)[o]
BP Pipelines (Alaska) Inc. (United States)
BP Pipelines (BTC) Limited (United Kingdom)
BP Pipelines (North America) Inc. (United States)
BP Pipelines (SCP) Limited (United Kingdom)
BP Pipelines (TANAP) Limited (United Kingdom)
BP Polska Services Sp. z o.o. (Poland)
BP Portugal-Comercio de Combustiveis e Lubrificantes SA (Portugal)
BP Poseidon Limited (United Kingdom)
BP Products North America Inc. (United States)
BP Properties Limited (United Kingdom)[f]
BP Raffinaderij Rotterdam B.V. (Netherlands)
BP Refinery (Kwinana) Proprietary Limited (Australia)
BP Refining & Petrochemicals GmbH (Germany)
BP Regional Australasia Holdings Pty Ltd (Australia)
BP Russian Investments Limited (United Kingdom)
BP Services International Limited (United Kingdom)
BP Shafag-Asiman Limited (United Kingdom)
BP Sharjah Limited (In Liquidation) (United Kingdom)
BP Shipping Limited (United Kingdom)
BP Singapore Pte. Limited (Singapore)
BP Solar Energy North America LLC (United States)
BP Solar Espana, S.A. Unipersonal (Spain)
BP Solar International Inc. (United States)
BP Solar Pty Ltd (Australia)
BP South East Asia Limited (United Kingdom)[f]
BP Southern Africa Proprietary Limited (South Africa, 75.00%)
BP Southern Cone Company (United States)
BP Subsea Well Response (Brazil) Limited (United Kingdom)
BP Subsea Well Response Limited (United Kingdom)
BP Sutton Limited (In Liquidation) (United Kingdom)
BP Taiwan Marketing Limited (Taiwan)
BP Tanjung IV Limited (United Kingdom)
BP Technology Ventures Inc. (United States)
BP Toplivnaya Kompanya LLC (Russian Federation)
BP Trade and Supply (Germany) GmbH,Hamburg (Germany)
BP Trading Limited (United Kingdom)[f]
BP Train 2/3 Holding SRL (Barbados)
BP Transportation (Alaska) Inc. (United States)
BP Trinidad and Tobago LLC (United States, 70.00%)
BP Trinidad Processing Limited (Trinidad and Tobago)
BP Turkey Refining Limited (United Kingdom)[f]
BP Venezuela Investments B.V. (Netherlands)
BP West Aru I Limited (United Kingdom)
BP West Aru II Limited (United Kingdom)
BP West Coast Products LLC (United States)
BP West Papua I Limited (United Kingdom)
BP West Papua III Limited (United Kingdom)
BP Wind Energy North America Inc. (United States)
BP Wiriagar Ltd. (United States)
BP World-Wide Technical Services Limited (United Kingdom)
BP Zhuhai Chemical Company Limited (China, 85.00%)
BP+Amoco International Limited (United Kingdom)[f]
BPA Investment Holding Company (United States)
BPNE International B.V. (Netherlands)
BPRY Caribbean Ventures LLC (United States, 70.00%)
Brian Jasper Nominees Pty Ltd (Australia)
Britannic Energy Trading Limited (United Kingdom)
Britannic Investments Iraq Limited (United Kingdom)
Britannic Strategies Limited (United Kingdom)
Britannic Trading Limited (United Kingdom)
British Pipeline Agency Limited (United Kingdom, 50.00%)[p q]
Britoil Limited (United Kingdom)
BTC Pipeline Holding Company Limited (United Kingdom)
Burmah Castrol Australia Pty Ltd (Australia)[r]
Burmah Castrol Holdings Inc. (United States)
Burmah Castrol PLC (United Kingdom)[f]
Burmah Castrol South Africa (Pty) Limited (South Africa)
Burmah Chile S.A. (Chile)
Burmah Fuels Australia Pty Ltd (Australia)
BXL Plastics Limited (United Kingdom)
Cadman DBP Limited (United Kingdom)
Cape Vincent Wind Power, LLC (United States)
Casitas Pipeline Company (United States)
Castrol (China) Limited (Hong Kong)
Castrol (Ireland) Limited (Ireland)
Castrol (Shenzhen) Company Limited (China)
Castrol (Switzerland) AG (Switzerland)
Castrol (U.K.) Limited (United Kingdom)
Castrol Australia Pty. Limited (Australia)
CASTROL Austria GmbH (Austria)
Castrol B.V. (Netherlands)
Castrol BP Petco Limited Liability Company (Vietnam, 65.00%)
Castrol Brasil Ltda. (Brazil)
Castrol Caribbean & Central America Inc. (United States)
Castrol Colombia Limitada (Colombia)
Castrol Del Peru S.A. (Peru, 99.49%)
Castrol Hungária Trading Co. Ltd. (Castrol Hungária Kereskedelmi Kft) (Hungary)[d]
Castrol India Limited (India, 71.03%)
Castrol Industrial North America Inc. (United States)
Castrol Industrie und Service GmbH (Germany)
Castrol KK (Japan, 65.65%)
Castrol Limited (United Kingdom)
Castrol Lubricants (CR), s.r.o. (Czech Republic)
Castrol Lubricants RO S.R.L (Romania)
Castrol Mexico, S.A. de C.V. (Mexico)
Castrol Offshore Limited (United Kingdom)
Castrol Pakistan (Private) Limited (Pakistan)
Castrol Philippines, Inc. (Philippines)
Castrol Servicos Ltda. (Brazil)
Castrol Slovensko, s.r.o. (Slovakia)
Castrol South Africa Proprietary Limited (South Africa)
Castrol Ukraine LLC (Ukraine)[d]
Castrol Zimbabwe (Private) Limited (Zimbabwe)
Centrel Pty Ltd (Australia)
CH-Twenty Holdings LLC (United States)
CH-Twenty, Inc. (United States)
Clarisse Holdings Pty Ltd (Australia)
Coastwise Trading Company, Inc. (United States)
Consolidada de Energia y Lubricantes, (CENERLUB) C.A. (Venezuela, Bolivarian Republic of)
Conti Cross Keys Inn, Inc. (United States)
Coro Trading NZ Limited (New Zealand)
Cuyama Pipeline Company (United States)
Delta Housing Inc. (United States)
Dermody Developments Pty Ltd (Australia)
Dermody Holdings Pty Ltd (Australia)
Dermody Investments Pty Ltd (Australia)
Dermody Petroleum Pty. Ltd. (Australia)
Dolvik Utvikling AS (Norway)
Dome Beaufort Petroleum Limited (Canada)
Dome Beaufort Petroleum Limited (March 1980) Limited Partnership (Canada)[c]
Dome Beaufort Petroleum Limited 1979 Partnership No. 1 (Canada)[c]
Dome Wallis (1980) Limited Partnership (Canada, 92.50%)[c]
Dradnats, Inc. (United States)
Duckhams Oils (Thailand) Company Limited (Thailand, 50.42%)
ECM Markets SA (Pty) Ltd (South Africa, 75.00%)
Edom Hills Project 1, LLC (United States)
Elite Customer Solutions Pty Ltd (Australia)
Elm Holdings Inc. (United States)
Energy Caspian Corporation (Virgin Islands, British)[a]
Energy Global Investments (USA) Inc. (United States)
Enstar LLC (United States)

The parent company financial statements of BP p.l.c. on pages 196-213 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

15. Related undertakings of the group – continued

ESJ US Holdings LLC (United States)
Europa Oil NZ Limited (New Zealand)
Exomet, Inc. (United States)
Expandite Contract Services Limited (United Kingdom)
Exploration (Luderitz Basin) Limited (United Kingdom)
Exploration Service Company Limited (United Kingdom)
F&H Pipeline Company (United States)
Flat Ridge 2 Holdings LLC (United States)
Flat Ridge Wind Energy, LLC (United States)
Foseco Chile Ltda. (Chile)
Foseco Holding International B.V. (Netherlands)
Foseco Holding, Inc. (United States)
Foseco, Inc. (United States)
Fosroc Expandite Limited (United Kingdom)
Fosven, CA (Venezuela, Bolivarian Republic of)
Fowler Ridge Holdings LLC (United States)
Fowler Ridge I Land Investments LLC (United States)
Fowler Ridge II Holdings LLC (United States)
Fowler Ridge III Wind Farm LLC (United States)
FreeBees B.V. (Netherlands)
Fuel & Retail Aviation Sweden AB (Sweden)
Fuelplane-Sociedade Abastecedora de Aeronaves, Unipessoal, Lda (Portugal)
Gardena Holdings Inc. (United States)
Gasolin GmbH (Germany)
Gasolinera Industrial S.L. (Spain)
GOAM 1 S A S (Colombia)
GOMH Holdings, Inc. (United States)
Grampian Aviation Fuelling Services Limited (United Kingdom)
Grangemouth Holdings Limited (United Kingdom)
Grangemouth Properties Limited (United Kingdom)
Guangdong Investments Limited (United Kingdom)
HAM Fuel & Retail Aviation Deutschland GmbH (Germany)
Highlands Ethanol, LLC (United States)
Hydrogen Energy International Limited (United Kingdom)
IGI Resources, Inc. (United States)
International Card Centre Limited (United Kingdom)
Iraq Petroleum Company Limited (United Kingdom)
J & A Petrochemical Sdn. Bhd. (Malaysia)
Jupiter Insurance Limited (Guernsey)
Kabulonga Properties Limited (Zambia)
Ken-Chas Reserve Company (United States)
Kenilworth Oil Company Limited (United Kingdom)[f]
Korea Energy Investment Holdings B.V. (Netherlands)
Latin Energy Argentina S.A. (Argentina)
Lebanese Aviation Technical Services S.A.L. (Lebanon, 99.70%)
Lubricants UK Limited (United Kingdom)
Mardi Gras Endymion Oil Pipeline Company, LLC (United States)
Mardi Gras Transportation System Inc. (United States)
Markoil, S.A. Unipersonal (Spain)
Masana Petroleum Solutions (Pty) Ltd (South Africa)[q s]
Mayaro Initiative for Private Enterprise Development (Trinidad and Tobago, 70.00%)[d]
Mehoopany Holdings LLC (United States)
Mes Tecnologia en Servicios y Energia, S.A. de C.V. (Mexico)
Minza Pty. Ltd. (Australia)
Mountain City Remediation, LLC (United States)
No. 1 Riverside Quay Proprietary Limited (Australia)
Nordic Lubricants A/S (Denmark)
Nordic Lubricants AB (Sweden)
Nordic Lubricants Oy (Finland)
North America Funding Company (United States)
Oelwerke Julius Schindler GmbH (Germany)
OMD87, Inc. (United States)
Omega Oil Company (United States)
Orion Delaware Mountain Wind Farm LP (United States)[c]
Orion Energy Holdings, LLC (United States)
Orion Energy L.L.C. (United States)
Orion Post Land Investments, LLC (United States)
Pacroy (Thailand) Co., Ltd. (Thailand, 39.00%)[q]
Pan American Petroleum Company of California (United States)
Pan American Petroleum Corporation (United States)
Peaks America Inc. (United States)
Pearl River Delta Investments Limited (United Kingdom)
Phoenix Petroleum Services, Limited Liability Company (Iraq)
PHP Construction Holdings, Inc. (United States)
PHP Trading Holdings, Inc. (United States)
Products Cogeneration Company (United States)
Produits Métallurgie Doittau SA - PROMEDO (France)
ProGas Limited (Canada)
ProGas U.S.A., Inc. (United States)
Prospect International, C.A. (Venezuela, Bolivarian Republic of, 99.90%)
PT BP Petrochemicals Indonesia (Indonesia)
PT Cakrawala Tata Sentosa (Indonesia, 68.03%)
PT Castrol Indonesia (Indonesia, 68.30%)
PT Jasatama Petroindo (Indonesia)
RB Raffinerie GmbH (Germany)
Reading Investment (Nominee) Limited (United Kingdom)
Reax Industria e Comercio Ltda. (Brazil)
Remediation Management Services Company (United States)
Richfield Oil Corporation (United States)
Rolling Thunder I Power Partners, LLC (United States)
Ropemaker Deansgate Limited (United Kingdom)
Ropemaker Properties Limited (United Kingdom)
Ruehl Gesellschaft m.b.H. & Co KG. (Austria)[c]
Rural Fuel Limited (New Zealand)
Saturn Insurance Inc. (United States)
Setra Lubricants (Russian Federation)
Setra Lubricants Kazakhstan LLP (Kazakhstan)[c]
Sherbino I Holdings LLC (United States)
Sherbino II Wind Farm LLC (United States)
Sherbino Mesa I Land Investments LLC (United States)
Shine Top International Investment Limited (Hong Kong)
Silver Star I Power Partners, LLC (United States)
Sociedade de Promocao Imobiliaria Quinta do Loureiro, SA (Portugal)
Société de Gestion de Dépots d'Hydrocarbures - GDH (France)
SOFAST Limited (Thailand)[t]
Southeast Texas Biofuels LLC (United States)
Southern Ridge Pipeline Holding Company (United States)
Southern Ridge Pipeline LP LLC (United States)
SRHP (France, 99.99%)
Standard Oil Company, Inc. (United States)
Taradadis Pty. Ltd. (Australia)
TEA Comercio E Participacoes Ltda. (Brazil)
Telcom General Corporation (United States, 99.96%)
Terrapin Creek Wind Energy LLC (United States)
Terre de Grace Partnership (Canada, 75.00%)
The Anaconda Company (United States)
The BP Share Plans Trustees Limited (United Kingdom)[f]
The Burmah Oil Company (Pakistan Trading) Limited (United Kingdom)
The Standard Oil Company (United States)
TJKK (Japan)
TOC-Rocky Mountains Inc. (United States)
Toledo Refinery Holding Company LLC (United States)
Trinity Hills Wind Farm LLC (United States)
TSG Polska Spolka z ograniczona odpowiedzialnocia (Poland)
TSG Tankstellen Support GmbH (Germany)
Union Texas International Corporation (United States)
UT Petroleum Services, LLC (United States)
Vastar Energy, Inc. (United States)
Vastar Gas Marketing, Inc. (United States)
Vastar Holdings, Inc. (United States)
Vastar Pipeline, LLC (United States)
Vastar Power Marketing, Inc. (United States)
Verano Collateral Holdings LLC (United States)
Viceroy Investments Limited (United Kingdom)
VTA Verfahrenstechnik und Automatisierung GmbH (Germany)
Warrenville Development Ltd. Partnership (United States)[c]
Water Way Trading and Petroleum Services LLC (Iraq)
Welchem, Inc. (United States)
West Kimberley Fuels Pty Ltd (Australia)
Westlake Houston Development, LLC (United States)
Whiting Clean Energy, Inc. (United States)
Windpark Energy Nederland B.V. (Netherlands)
ZAO Baltic Petroleum (Russian Federation)

The parent company financial statements of BP p.l.c. on pages 196-213 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

15. Related undertakings of the group – continued

Related undertakings other than subsidiaries

A Flygbranslehantering AB (AFAB) (Sweden, 50.00%)
ABG Autobahn-Betriebe GmbH (Austria, 32.58%)
Abu Dhabi Marine Areas Limited (United Kingdom, 33.33%)[p]
Abu Dhabi Petroleum Company Limited (United Kingdom, 23.75%)
AFCO AB (Sweden, 33.33%)
AGES International GmbH & Co. KG, Langenfeld (Germany, 24.70%)[c]
AGES Maut System GmbH & Co. KG, Langenfeld (Germany, 24.70%)[c]
Air BP Copec S.A. (Chile, 51.00%)
Air BP Italia Spa (Italy, 50.00%)
Air BP Petrobahia Ltda. (Brazil, 50.00%)
Aircraft Fuel Supply B.V. (Netherlands, 28.57%)
Aircraft Refuelling Company GmbH (Austria, 33.33%)
Airport Fuel Services Pty. Limited (Australia, 20.00%)
Alaska Tanker Company, LLC (United States, 25.00%)
Alyeska Pipeline Service Company (United States, 48.44%)
Ambarli Depolama Hizmetleri Limited Sirketi (Turkey, 50.00%)
Ammenn GmbH (Germany, 50.00%)
Amoco Bolivia Oil and Gas Aktiebolag (Sweden, 60.00%)
Arabian Production and Marketing Lubricants Company (Saudi Arabia, 50.00%)
ARCO Solar Nigeria Ltd. (Nigeria, 40.00%)
Asian Acetyls Co., Ltd (Korea, Republic of, 34.00%)
ATAS Anadolu Tasfiyehanesi Anonim Sirketi (Turkey, 68.00%)
Atlantic 1 Holdings LLC (United States, 34.00%)
Atlantic 2/3 Holdings LLC (United States, 42.50%)
Atlantic 4 Holdings LLC (United States, 37.78%)
Atlantic LNG 2/3 Company of Trinidad and Tobago Unlimited (Trinidad and Tobago, 42.50%)
Atlantic LNG 4 Company of Trinidad and Tobago Unlimited (Trinidad and Tobago, 37.78%)
Atlantic LNG Company of Trinidad and Tobago (Trinidad and Tobago, 34.00%)
Atlas Methanol Company Unlimited (Trinidad and Tobago, 36.90%)
Australasian Lubricants Manufacturing Company Pty Ltd (Australia, 50.00%)
Australian Terminal Operations Management Pty Ltd (Australia, 50.00%)
Auwahi Holdings, LLC (United States, 50.00%)[d]
Aviation Fuel Services Limited (United Kingdom, 25.00%)
Azerbaijan Gas Supply Company Limited (Cayman Islands, 23.06%)[p]
Azerbaijan International Operating Company (Cayman Islands, 40.50%)[u]
Baku-Tbilisi-Ceyhan Pipeline Finance B.V. (Netherlands, 30.10%)
Baku-Tbilisi-Ceyhan Pipeline Holding B.V. (Netherlands, 30.10%)
Bayernoil Raffineriegesellschaft mbH (Germany, 22.50%)
Beer GmbH (Germany, 50.00%)
Beer GmbH & Co. Mineralol-Vertriebs-KG (Germany, 50.00%)[c]
BGFH Betankungs-Gesellschaft Frankfurt-Hahn GbR (Germany, 50.00%)[c]
Black Hill Industrial Estate Limited (United Kingdom, 49.00%)
Blendcor (Pty) Limited (South Africa, 37.50%)
BP Dhofar LLC (Oman, 49.00%)
BP Guangzhou Development Oil Product Co., Ltd (China, 40.00%)
BP India Limited (India, 51.00%)
BP PetroChina Petroleum Co., Ltd (China, 49.00%)
BP Petronas Acetyls Sdn. Bhd. (Malaysia, 70.00%)
BP Sinopec (ZheJiang) Petroleum Co., Ltd (China, 40.00%)
BP Sinopec Marine Fuels Pte. Ltd. (Singapore, 50.00%)
BP YPC Acetyls Company (Nanjing) Limited (China, 50.00%)
BP-Husky Refining LLC (United States, 50.00%)
BP-Japan Oil Development Company Limited (United Kingdom, 50.00%)
Braendstoflageret Kobenhavns Lufthavn I/S (Denmark, 33.33%)[c]
BTC International Investment Co. (Cayman Islands)[v]
Butamax™ Advanced Biofuels LLC (United States, 50.00%)
Caesar Oil Pipeline Company, LLC (United States, 56.00%)
Cairns Airport Refuelling Service Pty Ltd (Australia, 25.00%)
Cantera K-3 Limited Partnership (United States, 39.00%)[c]
Castrol Cuba S.A. (Cuba, 50.00%)
Castrol DongFeng Lubricant Co., Ltd (China, 50.00%)
CCWE Holdings LLC (United States, 33.33%)
Cedar Creek II Holdings LLC (United States, 50.00%)
Cedar Creek II, LLC (United States, 50.00%)
Cedar Creek Wind Energy, LLC (United States, 33.33%)
Cekisan Depolama Hizmetleri Limited Sirketi (Turkey, 35.00%)
Central African Petroleum Refineries (Pvt) Ltd (Zimbabwe, 20.75%)
Chicap Pipe Line Company (United States, 56.17%)
China American Petrochemical Company, Ltd. (CAPCO) (Taiwan, 61.36%)
China Aviation Oil (Singapore) Corporation Ltd (Singapore, 20.03%)
Cleopatra Gas Gathering Company, LLC (United States, 54.00%)
Coastal Oil Logistics Limited (New Zealand, 25.00%)
Combined Refuelling Service VOF (Netherlands, 25.00%)
Compania de Inversiones El Condor Limitada (Chile, 99.00%)
Concessionaria Stalvedro SA (Switzerland, 50.00%)
CSG Convenience Service GmbH (Germany, 24.80%)
Cypress Pipeline Company, L.L.C. (United States, 50.00%)
Danish Refuelling Service I/S (Denmark, 33.33%)[c]
Danish Tankage Services I/S (Denmark, 50.00%)[c]
Destin Pipeline Company, L.L.C. (United States, 66.67%)
DHC Solvent Chemie GmbH (Germany, 50.00%)
Dinarel S.A. (Uruguay, 24.00%)
Direct Fuels Limited (New Zealand, 30.07%)
Dusseldorf Fuelling Services GbR (Germany, 33.00%)[c]
Dusseldorf Tank Services GbR (Germany, 33.00%)[c]
East Tanka Petroleum Company "ETAPCO" (Egypt, 50.00%)
Ekma Oil Company "EKMA" (Egypt, 50.00%)
El Temsah Petroleum Company "PETROTEMSAH" (Egypt, 25.00%)
EMDAD Aviation Fuel Storage FZCO (United Arab Emirates, 33.00%)
Emoil Storage Company FZCO (United Arab Emirates, 20.00%)
Endymion Oil Pipeline Company, LLC (United States, 75.00%)
Energenomics LLC (United States, 50.00%)
Energy Emerging Investments, LLC (United States, 60.00%)
Entrepot petrolier de Chambery (France, 32.00%)
Entrepôt Pétrolier de Puget sur Argens-EPPA (France, 58.25%)
Erdol-Lagergesellschaft m.b.H. (Austria, 23.00%)
Eroil Mineraloel GmbH-Diehl (Germany, 50.00%)
Esma Petroleum Company "ESMA" (Egypt, 50.00%)
Estonian Aviation Fuelling Services (Estonia, 49.00%)
Etzel-Kavernenbetriebsgesellschaft mbH & Co. KG (Germany, 33.00%)[c]
Etzel-Kavernenbetriebs-Verwaltungsgesellschaft mbH (Germany, 33.33%)[c]
FFS Frankfurt Fuelling Services (GmbH & Co.) OHG (Germany, 33.00%)[c]
Fibil SA (Switzerland, 50.00%)
Fip Verwaltungs GmbH (Germany, 50.00%)
Flat Ridge 2 Wind Energy LLC (United States, 50.00%)
Flat Ridge 2 Wind Holdings LLC (United States, 50.00%)
Flughafen Hannover Pipeline Verwaltungsgesellschaft mbH (Germany, 50.00%)
Flughafen Hannover Pipelinegesellschaft mbH & Co. KG (Germany, 50.00%)
Flytanking AS (Norway, 50.00%)
Foreseer Ltd (United Kingdom, 25.00%)
Formosa BP Chemicals Corporation (Taiwan, 50.00%)
Fowler I Holdings LLC (United States, 50.00%)
Fowler II Holdings LLC (United States, 50.00%)
Fowler Ridge II Wind Farm LLC (United States, 50.00%)
Fowler Ridge Wind Farm LLC (United States, 50.00%)
Fuelling Aviation Service-FAS (France, 50.00%)[d]
Fundación para la Eficiencia Energética de la Comunidad Valenciana (Spain, 33.33%)[d]
Gardermeon Fuelling Services AS (Norway, 33.33%)
Georg Reitberger Mineralole GmbH & Co. KG (Germany, 50.00%)[c]
Georg Reitberger Mineralöle Verwaltungs GmbH (Germany, 50.00%)[c]
Georgian Pipeline Company (Cayman Islands, 40.50%)[u]
Gezamenlijke Tankdienst Schiphol B.V. (Netherlands, 50.00%)
GISSCO S.A. (Greece, 50.00%)
GlobeFuel Systems & Services GmbH (Germany, 33.00%)
Goshen Phase II LLC (United States, 50.00%)
Gothenburgh Fuelling Company AB (GFC) (Sweden, 33.33%)
Gravcap, Inc. (United States, 25.00%)
Groupement Pétrolier de Saint Pierre des Corps-GPSPC (France, 20.00%)
Groupement Pétrolier de Strasbourg (France, 33.33%)
Groupement pour l'Avitaillement de Lyon Saint-Exupéry-GALYS (France, 39.93%)[d]
Guangdong Dapeng LNG Company Limited (China, 30.00%)
Gulf Of Suez Petroleum Company "GUPCO" (Egypt, 50.00%)
GVÖ Gebinde-Verwertungsgesellschaft der Mineralölwirtschaft mbH (Germany, 21.00%)
H & G Contracting Services Limited (United Kingdom, 33.50%)
Hamburg Tank Service (HTS) GbR (Germany, 33.00%)[c]
Havacilik Yakit Ikmali Operasyon Ortakligi (Turkey, 25.00%)[c]
Heinrich Fip GmbH & Co. KG (Germany, 50.00%)[c]
Heliex Power Limited (United Kingdom, 32.40%)[m]
HFS Hamburg Fuelling Services GbR (Germany, 25.00%)[c]
Hiergeist Heizolhandel GmbH & Co. KG (Germany, 50.00%)[c]
Hiergeist Verwaltung GmbH (Germany, 50.00%)
Hydrogen Energy International LLC (United States, 50.00%)
In Salah Gas Ltd (Jersey, 25.50%)
In Salah Gas Services Ltd (Jersey, 25.50%)
Independent Petroleum Laboratory Limited (New Zealand, 41.52%)
India Gas Solutions Private Limited (India, 50.00%)
Iraq Petroleum Company, Limited (In Liquidation) (United Kingdom, 23.75%)
Jamaica Aircraft Refuelling Services Limited (Jamaica, 51.00%)
Kingston Research Limited (United Kingdom, 50.00%)
Klaus Köhn GmbH (Germany, 50.00%)
Köhn & Plambeck GmbH & Co. KG (Germany, 50.00%)
Kurt Ammenn GmbH & Co. KG (Germany, 50.00%)[c]
LFS Langenhagen Fuelling Services GbR (Germany, 50.00%)[c]
Lotos-Air BP Polska Spółka z ograniczon ą odpowiedzialno ścią (Poland, 50.00%)
Maatschap Europoort Terminal (Netherlands, 25.00%)
Mach Monument Aviation Fuelling Co. Ltd. (Iraq, 70.00%)
Malmo Fuelling Services AB (Sweden, 33.33%)
Manchester Airport Storage and Hydrant Company Limited (United Kingdom, 25.00%)
Mars Oil Pipeline Company (United States, 28.50%)
MATELUB S.A.R.L. (Baldersheim/Frankreich) (France, 80.00%)
McFall Fuel Limited (New Zealand, 30.07%)
Mediteranean Gas Co. "MEDGAS" (Egypt, 25.00%)
Mehoopany Wind Energy LLC (United States, 50.00%)
Mehoopany Wind Holdings LLC (United States, 50.00%)
Middle East Lubricants Company LLC (United Arab Emirates, 29.33%)
Milne Point Pipeline, LLC (United States, 50.00%)
Mineralol-Handels-Gesellschaft mbH, Celle (Germany, 50.00%)
Mobene GmbH & Co. KG (Germany, 50.00%)[c]
Mobene Verwaltungs-GmbH (Germany, 50.00%)
N.V. Rotterdam-Rijn-Pijpleiding Maatschappij (RRP) (Netherlands, 33.33%)

The parent company financial statements of BP p.l.c. on pages 196-213 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

15. Related undertakings of the group – continued

Natural Gas Vehicles Company "NGVC" (Egypt, 40.00%)
New Zealand Oil Services Limited (New Zealand, 50.00%)
NFX Combustíveis Marítimos Ltda. (Brazil, 50.00%)
Nigermed Petroleum S.A. (Panama, 50.00%)
Nord-West Oelleitung GmbH (Germany, 42.49%)
North Ghara Petroleum Company (NOGHCO) (Egypt, 30.00%)
North October Petroleum Company "NOPCO" (Egypt, 50.00%)
Oak Hill Venture Fund Limited Partnership (United States, 50.00%)[c]
Ocwen Energy Pty Ltd (Australia, 49.50%)
OJSC Oil Company Rosneft (Russian Federation, 19.75%)
Okeanos Gas Gathering Company, LLC (United States, 66.67%)
Oleoductos Canarios, S.A. (Spain, 20.00%)
OptoAtmospherics Inc (United States, 27.20%)[m]
Oslo Lufthaven Tankanlegg AS (Norway, 33.33%)
PAE E & P Bolivia Limited (Bahamas, 60.00%)
PAE Oil & Gas Bolivia Ltda. (Bolivia, 60.00%)
Pan American Energy Chile Limitada (Chile, 60.00%)
Pan American Energy do Brasil Ltda. (Brazil, 60.00%)
Pan American Energy Holdings Ltd. (Virgin Islands, British, 60.00%)
Pan American Energy Iberica S.L. (Spain, 60.00%)
Pan American Energy Investments Ltd. (Virgin Islands, British, 60.00%)
Pan American Energy LLC (United States, 60.00%)
Pan American Energy Uruguay S.A. (Uruguay, 60.00%)
Pan American Fueguina S.A. (Argentina, 60.00%)
Pan American Sur S.A. (Argentina, 60.00%)
Paul Harling Mineralole GmbH & Co. KG (Germany, 50.00%)[c]
Peninsular Aviation Services Company Limited (Saudi Arabia, 25.00%)
Pentland Aviation Fuelling Services Limited (United Kingdom, 25.00%)[p]
Petro Shadwan Petroleum Company "PETRO SHADWAN" (Egypt, 25.00%)
Petrostock SA (Switzerland, 50.00%)
Pharaonic Petroleum Company "PhPC" (Egypt, 25.00%)
Phu My 3 BOT Power Company Limited (Vietnam, 33.33%)
Prince William Sound Oil Spill Response Corporation (United States, 25.00%)
Proteus Oil Pipeline Company, LLC (United States, 75.00%)
PT Petro Storindo Energi (Indonesia, 30.00%)
PTE Pipeline LLC (United States, 32.00%)
Raffinerie de Strasbourg (France, 33.33%)
Rahamat Petroleum Company (PETRORAHAMAT) (Egypt, 50.00%)
Raimund Mineraloel GmbH (Germany, 50.00%)
RAPISA (Greece, 62.50%)
Raststaette Glarnerland AG, Niederurnen (Switzerland, 20.00%)
RD Petroleum Limited (New Zealand, 49.00%)
Resolution Partners LLP (United States, 68.00%)
Rhein-Main-Rohrleitungstransportgesellschaft mbH (Germany, 35.00%)
Rio Grande Pipeline Company (United States, 30.00%)[c]
RocketRoute Limited (United Kingdom, 22.50%)[m]
Romanian Fuelling Services S.R.L. (Romania, 50.00%)
Routex B.V. (Netherlands, 25.00%)
Rudeis Oil Company "RUDOCO" (Egypt, 50.00%)
Ruhr Oel GmbH (ROG) (Germany, 50.00%)
Rundel Mineraloelvertrieb GmbH (Germany, 50.00%)
S&JD Robertson North Air Limited (United Kingdom, 49.00%)
SABA-Sociedade Abastecedora de Aeronaves, Lda (Portugal, 25.00%)
SAFCO SA (Greece, 33.00%)
Salzburg Fuelling GmbH (Austria, 33.00%)
Samsung-BP Chemicals Co., Ltd (Korea, Republic of, 51.00%)
Saraco SA (Switzerland, 20.00%)
SBB Dortmund GmbH (Germany, 25.00%)
Servicios Logísticos de Combustibles de Aviación, S.L (Spain, 50.00%)
Shanghai SECCO Petrochemical Company Limited (China, 50.00%)
Sharjah Aviation Services Co. LLC (United Arab Emirates, 49.00%)
Sharjah Pipeline Company LLC (United Arab Emirates, 24.01%)[w]
Shell and BP South African Petroleum Refineries (Pty) Ltd (South Africa, 37.50%)
Shell Mex and B.P. Limited (United Kingdom, 40.00%)
Shell-Statoil Refuelling (Billund) I/S (Denmark, 50.00%)
Shenzhen Cheng Yuan Aviation Oil Company Limited (China, 25.00%)
Shenzhen Dapeng LNG Marketing Company Limited (China, 30.00%)
Sherbino I Wind Farm LLC (United States, 50.00%)
SKA Energy Holdings Limited (United Arab Emirates, 50.00%)
Société d'Avitaillement et de Stockage de Carburants Aviation "SASCA" (France, 40.00%)
Société de Gestion de Produits Pétroliers-SOGEPP (France, 37.00%)
Société de Participations dans l'Industrie et le Transport du Pétroles S.P.I.T.P. (France, 23.69%)
South Caucasus Pipeline Company Limited (Cayman Islands, 28.83%)
South Caucasus Pipeline Holding Company Limited (Cayman Islands, 28.83%)
South Caucasus Pipeline Option Gas Company Limited (Cayman Islands, 28.83%)
South China Bluesky Aviation Oil Company Limited (China, 24.50%)
ST-Airport Services Pte Ltd (Singapore, 33.00%)
Stansted Intoplane Company Limited (United Kingdom, 20.00%)
STDG Strassentransport Dispositions Gesellschaft mbH (Germany, 50.00%)
Stonewall Resources Ltd. (Virgin Islands, British, 60.00%)
Sunderland Oil Storage Limited (United Kingdom, 50.00%)
Sunrise Oil Sands Partnership (Canada, 50.00%)[c]
Tankanlage AG Mellingen (Switzerland, 33.30%)
TAR-Tankanlage Ruemlang AG (Switzerland, 27.30%)
TAU Tanklager Auhafen AG (Switzerland, 50.00%)
Team Terminal B.V. (Netherlands, 22.80%)
Tecklenburg GmbH (Germany, 50.00%)
Tecklenburg GmbH & Co. Energiebedarf KG (Germany, 50.00%)[c]
Terminales Canarios, S.L. (Spain, 50.00%)
Terminales Maritimas Patagonicas SA (TERMAP S.A.) (Argentina, 60.00%)
TFSS Turbo Fuel Services Sachsen GbR (Germany, 20.00%)[c]
TGFH Tanklager-Gesellschaft Frankfurt-Hahn GbR (Germany, 50.00%)
TGH Tankdienst-Gesellschaft Hamburg GbR (Germany, 33.33%)[c]
TGHL Tanklager-Gesellschaft Hannover-Langenhagen GbR (Germany, 50.00%)[c]
TGK Tanklagergesellschaft Koln-Bonn (Germany, 20.00%)[c]
The Baku-Tbilisi-Ceyhan Pipeline Company (Cayman Islands, 30.10%)
The Consolidated Petroleum Company Limited (United Kingdom, 50.00%)
The Consolidated Petroleum Supply Company Limited (United Kingdom, 50.00%)
The New Zealand Refining Company Limited (New Zealand, 21.19%)
The Sullom Voe Association Limited (United Kingdom, 33.33%)
TLM Tanklager Management GmbH (Austria, 49.00%)
TLS Tanklager Stuttgart GmbH (Germany, 45.00%)
Torsina Oil Company "TORSINA" (Egypt, 37.50%)
Trafineo GmbH & Co. KG (Germany, 75.00%)[c]
Trafineo Verwaltungs-GmbH (Germany, 75.00%)[c]
Trans Adriatic Pipeline AG (Switzerland, 20.00%)
TransTank GmbH (Germany, 50.00%)
Unimar LLC (United States, 50.00%)[d]
United Gas Derivatives Company "UGDC" (Egypt, 33.33%)
United Kingdom Oil Pipelines Limited (United Kingdom, 33.50%)
Ursa Oil Pipeline Company LLC (United States, 22.69%)
VIC CBM Limited (United Kingdom, 50.00%)
Virginia Indonesia Co. CBM Limited (United Kingdom, 50.00%)
Virginia Indonesia Co., LLC (United States, 50.00%)
Virginia International Co., LLC (United States, 50.00%)
Walton-Gatwick Pipeline Company Limited (United Kingdom, 42.33%)
West London Pipeline and Storage Limited (United Kingdom, 30.50%)
West Morgan Petroleum Company (PETROMORGAN) (Egypt, 50.00%)
Wilprise Pipeline Company, L.L.C. (United States, 25.30%)
Wiri Oil Services Limited (New Zealand, 27.78%)
Xact Downhole Telementry Inc (Canada, 25.70%)[m]
Yangtze River Acetyls Co., Ltd (China, 51.00%)

[a] Ordinary shares and preference shares
[b] Common stock and preference shares
[c] Partnership interest
[d] Member interest
[e] Preferred series B shares
[f] Interest held directly by BP p.l.c.
[g] 99% held by BP p.l.c.
[h] A and B shares
[i] 1% held by BP p.l.c.
[j] Common stock, preferred stock class A and preferred stock class B
[k] 0.008% held by BP p.l.c.
[l] Bearer shares
[m] Preference shares
[n] 93.56% ordinary shares and 81.00% preference shares
[o] 19.32% held by BP p.l.c.
[p] A shares
[q] Subsidiary in which the group does not hold a majority of the voting rights but exercises control over it
[r] Ordinary shares and redeemable preference shares
[s] 33.75% ordinary shares and 75% cumulative redeemable preference shares
[t] 100.00% ordinary shares and 58.63% preference shares
[u] Unlimited redeemable shares
[v] 0.52% A class and 29.58% B class
[w] B shares

The parent company financial statements of BP p.l.c. on pages 196-213 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.