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.

Report on the audit of the financial statements

Opinion
In our opinion:

- The financial statements of BP p.l.c. (the 'parent company') and its subsidiaries (the 'group') give a true and fair view of the state of the group's and of the parent company's affairs as at 31 December 2018 and of the group's profit for the year then ended.
- The group financial statements have been properly prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU) and IFRSs as issued by the International Accounting Standards Board (IASB).
- The parent company financial statements have been properly prepared in accordance with United Kingdom generally accepted accounting practice including FRS 101 'Reduced Disclosure Framework'.
- 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.

We have audited the financial statements of BP p.l.c. which comprise:

- Group income statement;
- Group statement of comprehensive income;
- Group and parent company statements of changes in equity;
- Group and parent company balance sheets;
- Group cash flow statement;
- Group related Notes 1 to 38 to the financial statements, including a summary of significant policies; and
- Parent company related Notes 1 to 14 to the financial statements, including a summary of significant accounting policies.

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

Basis for opinion
We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the auditor's responsibilities for the audit of the financial statements section of our report.

We are independent of the group and the parent company in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the Financial Reporting Council's (the 'FRC's') Ethical Standard as applied to listed public interest entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We confirm that the non-audit services prohibited by the FRC's Ethical Standard were not provided to the group or the parent company.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Summary of our audit approach

Key audit matters	The key audit matters that we identified in the current year were: • Impairment of Upstream oil and gas property, plant and equipment (PP&E) assets; • Accounting for acquisitions and disposals within the Upstream segment; • Impairment of exploration and appraisal assets; • Accounting for structured commodity transactions within the integrated supply and trading function, and the valuation of other level 3 financial instruments, where fraud risks may arise in revenue recognition; • User access management controls relating to financial systems; and • Management override of controls. Two key audit matters were identified by the previous auditor and described in their report for the year ended 31 December 2017 and are not included in our report for the year ended 31 December 2018. These were: • The determination of the liabilities, contingent liabilities and disclosures arising from the Gulf of Mexico oil spill- the provisions have substantially decreased from a quantitative perspective and the level of judgement in determining BP's liabilities has reduced significantly as legal settlements have been reached; and • US Tax reform - the reform was signed into law in 2017 and gave rise to a one-off taxation charge. Whilst the impact of the reform has continued to be assessed in 2018, the judgement required and quantitative impact in the current year is considerably lower. The previous auditor also included a key audit matter in respect of unauthorized trading activity in the integrated supply and trading function. This is covered by the key audit matter set out above covering the accounting for structured commodity transactions and valuation of certain level 3 financial instruments. They also identified a key audit matter in respect of the estimation of oil and gas reserves and resources, which we have considered in the context of impairment of Upstream oil and gas PP&E assets.
Materiality	We have set materiality for the current year at $750 million based on profit before tax and underlying replacement cost profit before interest and tax.

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Scoping	Our scope covered 136 components. Of these, 108 were full-scope audits, covering 71% of group revenue, and the remaining 28 were subject to specific procedures on certain account balances by component audit teams or the group audit team.
First year audit transition	The year ended 31 December 2018 is our first as auditor of the group. We commenced transition activities after our selection as auditor being announced in November 2016. These activities included: • Establishing independence from BP by exiting non-audit services which would be independence-impairing, as BP transitioned these to new service providers; • Establishing an appropriately resourced and skilled global audit team, including specialists, in all relevant locations; • Developing and delivering a bespoke "BP Academy" training course for Deloitte personnel joining the BP audit engagement; and • Holding introductory meetings with BP management. We commenced our audit planning procedures subsequent to us becoming independent on 16 October 2017. After establishing independence, our work included: • Shadowing the previous auditor through the 31 December 2017 audit, including attendance at key meetings, including audit committee meetings; • Reviewing the previous auditor's 2016 and 2017 audit files; • Reviewing historical accounting policies and accounting judgements through discussion with management and review and challenge of management's papers and supporting documentation; and • Conducting group audit team visits to components. These procedures built our understanding of the group which, together with our existing knowledge of the oil and gas industry, informed our audit risk assessment, through which we identified the risks of material misstatement to the group's financial statements. We presented our transition observations to the group's audit committee in a transition report in April 2018, with an update in May 2018. We presented further observations, together with our audit plan, in July 2018, and provided an update to our plan in December 2018.

Conclusions relating to going concern, principal risks and viability statement

Going concern

We have reviewed the directors' statement on page 111 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 group's and company's ability to continue to do so over a period of at least twelve months from the date of approval of the financial statements.

We considered as part of our risk assessment the nature of the group, its business model and related risks including where relevant the impact of Brexit, the requirements of the applicable financial reporting framework and the system of internal control. We evaluated the directors' assessment of the group's ability to continue as a going concern, including challenging the underlying data and key assumptions used to make the assessment, and evaluated the directors' plans for future actions in relation to their going concern assessment.

We are required to state whether we have anything material to add or draw attention to in relation to that statement required by Listing Rule 9.8.6R(3) and report if the statement is materially inconsistent with our knowledge obtained in the audit.

We confirm that we have nothing material to report, add or draw attention to in respect of these matters.

Principal risks and viability statement

Based solely on reading the directors' statements and considering whether they were consistent with the knowledge we obtained in the course of the audit, including the knowledge obtained in the evaluation of the directors' assessment of the group's and the company's ability to continue as a going concern, we are required to state whether we have anything material to add or draw attention to in relation to:

- the disclosures on pages 55-56 that describe the principal risks and explain how they are being managed or mitigated;
- the directors' confirmation on page 110 that they have carried out a robust assessment of the principal risks facing the group, including those that would threaten its business model, future performance, solvency or liquidity; or
- the directors' explanation on page 111 as to how they have assessed the prospects of the group, 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 group 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 are also required to report whether the directors' statement relating to the prospects of the group required by Listing Rule 9.8.6R(3) is materially inconsistent with our knowledge obtained in the audit.

We confirm that we have nothing material to report, add or draw attention to in respect of these matters.

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial statements of the current period and include the most significant assessed risks of material misstatement (whether or not due to fraud) that we identified.

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These matters included those which had the greatest effect on: the overall audit strategy, the allocation of resources in the audit; and directing the efforts of the engagement team.

Throughout the course of our audit we identify risks of material misstatement ('risks') and classify those risks according to their severity. In assigning a category we consider both the likelihood of a risk of a material misstatement and the potential magnitude of a misstatement in making the assessment. Certain risks are classified as 'significant' or 'higher' depending on their severity. The category of the risk determines the level of evidence we seek in providing assurance that the associated financial statement item is not materially misstated.

These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

<table>
<tr><th colspan="2">Impairment of upstream oil and gas PP&E assets</th></tr>
<tr><th>Key audit matter description</th><th>How the scope of our audit responded to the key audit matter</th></tr>
<tr><td>
The group balance sheet includes property, plant and equipment (PP&E) of $135 billion, of which $99 billion is oil and gas properties within the Upstream segment. As required by IAS 36 'Impairment of Assets', management performed a review of the upstream cash generating units (CGUs) for indicators of impairment and impairment reversal as at 31 December 2018.
Where such indicators were identified, management estimated the recoverable amount of the CGU to determine if any impairment charges or reversals were required. For the year ended 31 December 2018, BP recorded $400 million of Upstream impairment charges and $580 million of impairment reversals.
Through our risk assessment procedures, we have determined that there are three key estimates in management's review for indicators of impairment/reversal and the level of impairment charge/reversal to record where indicators are identified. These are:

Long-term oil and gas prices - BP's long-term oil and gas price assumptions have a significant impact on CGU impairment assessments and valuations performed across the portfolio, and are inherently uncertain. There is a risk that management's oil and gas price assumptions are not reasonable, leading to a material misstatement.
Discount rates - Given the long timeframes involved, certain impairment assessments and valuations are sensitive to the discount rate applied. There is a risk that discount rates do not reflect the return required by the market and the risks inherent in the cash flows being discounted, leading to a material misstatement. Determination of the appropriate discount rate can be judgemental.
Reserves estimates - A key input to impairment assessments and valuations is the production forecast, in turn closely related to the group's reserves estimates and field development assumptions. CGU-specific estimates are not generally material. However, material misstatements could arise either from systematic flaws in reserves estimation policies, or due to flawed estimates in a particularly material individual impairment test.

Whilst all CGUs must be assessed for indicators of impairment and impairment reversal annually, we focused on certain individual CGUs with a total carrying value of $21.8 billion which we determined would be most at risk of a material impairment ($750 million) as a result of a reasonably possible change in the key assumptions, particularly the long-term oil and gas price assumptions. Accordingly, we identified these as a significant audit risk. We also focused on assets with a further $31.5 billion of combined CGU carrying value which were less sensitive. We identified these as a higher audit risk as they would be potentially at risk in aggregate to a material impairment by a change in such assumptions. Further information regarding these sensitivities is given in Note 1.
</td><td>
We tested management's internal controls over the setting of oil and gas prices, discount rates and reserve estimates. In addition, we conducted the following substantive procedures.
Long-term oil and gas prices

We compared BP's oil and gas price assumptions against third-party forecasts, peer information and relevant market data to determine whether BP's forecasts were within the range of such forecasts.
In challenging management's forecasts, we considered the extent to which they reflected the energy transition due to climate change.

Discount rates

We independently evaluated BP's discount rates used in impairment tests with input from Deloitte valuation specialists.
We assessed whether country risks were appropriately reflected in BP's discount rates.

Reserves estimates

We performed a look-back analysis to check for indications of bias over time.
We reviewed BP's reserves estimation methods and policies, assisted by Deloitte reserves experts.
We assessed how these policies had been applied to seven internal reserves estimates.
We reviewed reports provided by external experts and assessed their scope of work and findings.
We assessed the competence, capability and objectivity of BP's internal and external reserve experts, through obtaining their relevant professional qualifications and experience.

Other procedures

We challenged management's cash generating unit determination, scrutinized the impairment and impairment reversal indicator analysis and considered whether there was any contradictory evidence present.
Where such indicators were identified, we validated that BP's asset impairment methodology was appropriate and tested the integrity of impairment models.
We compared hydrocarbon production forecasts and proved and probable reserves to reserve reports and our understanding of the life of fields.
We verified estimated future capital and operational costs by comparison to approved budgets and assessed them with reference to field production forecasts.
We also assessed these estimates against management's historical forecasting accuracy and whether the estimates had been determined and applied on a consistent basis across the group where relevant.

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Key observations	**Long-term oil and gas prices** We determined that BP’s Brent oil price forecasts are reasonable when compared against the range of other third-party forecasts. We challenged BP’s Henry Hub, NBP and Asian LNG price curves for periods when they were somewhat higher than the range of other third-party forecasts. However, management ran additional tests using a Henry Hub, NBP and Asian LNG price curve consistent with the range of third-party forecasts, which demonstrated that the carrying values recorded in the balance sheet are not impacted. **Discount rates** Our Deloitte valuation specialists calculated a different range for weighted average cost of capital than was determined by management. We also found that some simplifications are taken when making group-wide assumptions for country and asset-specific risk premium adjustments, and for calculating pre-tax discount rates, given the group's CGUs which operate in multiple tax jurisdictions. Management reperformed impairment tests using higher discount rates and only one impairment test was impacted, with a difference which was not significant. Accordingly we were satisfied with the results of the testing. We reviewed the disclosures included in Note 1 to the accounts in respect of price and discount rate assumptions used and confirmed that they were the same as those used in the impairment tests. **Reserves estimates** Having involved Deloitte oil and gas reserves experts in our testing, we concluded that the assumptions used to derive the estimates were reasonable.

Accounting for acquisitions and disposals within the Upstream segment	
Key audit matter description	**How the scope of our audit responded to the key audit matter**
There were certain acquisition and disposal transactions within the Upstream segment that required fair valuation of assets and liabilities acquired and disposed of, and consideration of complex accounting judgements, to which we devoted significant engagement team time and resource. Accordingly, this had a significant effect on our audit strategy. These transactions were: • The $10.3 billion acquisition of onshore US assets from BHP, including the fair valuation of assets and liabilities acquired; • The disposal of BP’s interest in the Greater Kuparuk Area in Alaska and simultaneous purchase of an incremental interest in the BP-operated Clair field in the UK North Sea; and • The disposal of BP’s interest in the Magnus field in the North Sea, where the consideration included a level 3 financial asset, the valuation of which depends on the future performance of Magnus.	We tested management’s internal key controls over the valuation assumptions and accounting approaches for each of these significant transactions. In addition, we conducted the following substantive procedures: • We reviewed the enacted sale and purchase agreements and management’s accounting analysis to corroborate that the accounting treatment applied was consistent with the underlying commercial terms. • With input from our valuations and reserves specialist teams, we reviewed and challenged management’s fair value estimates, focusing on the key assumptions (including pricing, discount rates and reserves risking estimates). • We tested the mechanical accuracy of the valuation models. • We assessed the independence, objectivity, competence and scope of work performed by BP’s third-party valuation specialist used in the acquisition from BHP.
Key observations	We noted that the assumptions underlying the fair value calculation for the onshore US assets acquired from BHP were at the conservative end of the range but concurred that the purchase price represented the fair value of the assets and liabilities acquired, in accordance with IFRS 3. We observed that in some cases, the fair values of oil and gas assets from certain market transactions, including the BHP acquisition, implied valuation assumptions that were more conservative than those used in value-in-use impairment calculations. The latter, as defined in IAS 36, represents management’s best estimate of the future cash flows of an asset, discounted at a market rate of return, whereas the former, as defined in IFRS 13 'Fair Value Measurement', is determined by the prices at which oil and gas assets are actually changing hands in orderly transactions under prevailing market conditions. We concluded that in their respective IFRS contexts, and in the presence of valid evidence, the use of different assumptions to estimate fair values and value in use was appropriate. We reviewed the disclosures included by management in Note 3 to the accounts and concluded that these are compliant with IFRS 3 requirements.

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Impairment of exploration and appraisal assets	
Key audit matter description	**How the scope of our audit responded to the key audit matter**
The group capitalizes exploration and appraisal (E&A) expenditure on a project-by-project basis in line with IFRS 6 'Exploration for and Evaluation of Mineral Resources'. At the end of 2018, $16.0 billion of E&A expenditure was carried in the group balance sheet. E&A activity is inherently risky and a significant proportion of projects fail, requiring the write-off of the related capitalized costs when the relevant criteria in IFRS 6 and BP's accounting policy are met. There is a risk that certain capitalized E&A costs are not written off promptly at the appropriate time, in line with information from, and decisions about E&A activities, and the impairment requirements of IFRS 6. Through our detailed risk assessment, which is based on our analysis of the portfolio of E&A assets held by BP, making reference to BP's own analysis of the same assets, we identified a significant risk in respect of certain specific assets in the Gulf of Mexico with a total carrying value of $2.3 billion, as certain licences in question have expired and a partner has recently withdrawn from other licences, and three licences elsewhere ($1.6 billion) which are scheduled to expire or require next phase decisions in 2019. BP is in negotiations to extend all these licences. Further details regarding the significant accounting judgement are given in Note 1 to the accounts.	We obtained an understanding of the group's E&A impairment assessment processes and tested management's controls. In addition, we conducted the following substantive procedures: We reviewed and challenged management's significant IFRS 6 impairment judgements, guided by our risk assessment, having regard to the impairment criteria of IFRS 6 and BP's accounting policy. We verified key facts relevant to significant carrying amounts (e.g. obtaining evidence of future E&A plans and budgets, evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms). We performed a licence-by-licence risk assessment of the group's E&A balance through to year end, to identify significant carrying amounts with a significant current period risk of impairment (e.g. new information from exploration activities, or imminent licence expiry). We performed a look-back analysis of impairment charges recorded in the period, and assessed whether impairment charges were timely. We tested the completeness and accuracy of information used in management's E&A impairment assessment, by reviewing and testing key controls over management's register of E&A licences and vouching key aspects of this to underlying support (e.g. licence documentation); holding meetings and discussions with operational and finance management; considering adverse changes in management's reserves and resource estimates associated with E&A assets; reviewing correspondence with regulators and joint arrangement partners; and considering the implications of capital allocation decisions. When considering capital allocation decision making, we considered whether any projects are unlikely to proceed on the grounds that they are not currently consistent with BP's strategy or which would otherwise have a prohibitively high environmental or social impact for the directors to sanction the necessary investment.
Key observations	We concluded that the key assumptions had been appropriately determined, the judgements management had made were appropriately supported, and no additional impairments were identified from the work we performed. Where BP had concluded that E&A costs should continue to be carried in respect of projects where licences had expired, we obtained appropriate evidence that there was ongoing correspondence with the relevant regulatory bodies, as referred to in Note 1 to the financial statements, to support management's judgement. We also confirmed management's view that they did not consider that the development of any of their assets is inconsistent with BP's strategy and stated climate change ambitions.

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<tr><th colspan="2">Accounting for structured commodity transactions (SCTs) within the integrated supply and trading function (IST), and the valuation of other level 3 financial instruments, where fraud risks may arise in revenue recognition</th></tr>
<tr><th>Key audit matter description</th><th>How the scope of our audit responded to the key audit matter</th></tr>
<tr><td>
In the normal course of business, the integrated supply and trading function (IST) enters into a variety of transactions for delivering value across the group's supply chain. The nature of these transactions requires significant audit effort be directed towards challenging management's valuation estimates or the adopted accounting treatment.

Accounting for structured commodity transactions: IST may also enter into a variety of transactions which we refer to as SCTs. We generally consider a SCT to be an arrangement having one of the following features:
a) two or more counterparties with non-standard contractual terms;
b) multiple commodity-based transactions; and/or
c) contractual arrangements entered into in contemplation of each other.

SCTs are often long-dated, can have a significant multi-year financial impact, and may require the use of complex valuation models or unobservable market inputs when determining their fair value, in which case they will be classified as level 3 financial instruments under IFRS 13, Fair Value Measurement.

There are inherent risks in the accounting for SCTs as these contracts are often complex and the associated accounting considerations often feature multiple elements, which are subject to management judgement, that will have a material impact on the presentation and disclosure of these transactions on the primary financial statements and key performance measures, including in particular whether finance debt should be recognized. We have identified the accounting for SCTs as a significant audit risk.

Level 3 financial instruments: Unlike other financial instruments whose values or inputs are readily observable and therefore more easily independently corroborated, there are certain transactions for which the valuation is inherently more subjective due to the use of either bespoke valuation models and/or unobservable inputs. These instruments are classified as level 3 financial assets or liabilities under IFRS 13. This degree of subjectivity also gives rise to potential fraud through management incorporating bias in determining fair values. Accordingly, we have identified these as a significant audit risk, and the area in which a fraud risk is most likely to arise in relation to revenue recognition.

As at 31 December 2018, the group's total financial assets and liabilities measured at fair value were $12.8 billion and $8.9 billion, of which level 3 derivative financial instruments were $3.6 billion and $3.1 billion, respectively.
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Accounting for structured commodity transactions:
For structured commodity transactions, we performed audit procedures to:

Evaluate the design, implementation and operating effectiveness of controls related to the review of such non-standard transactions, including the:

New activity integration control, which is designed to evaluate and approve the appropriateness of the new activity; and
Accounting policy review, which is designed to evaluate the appropriateness of accounting treatment in line with published IFRS accounting literature.

Develop an understanding of the commercial rationale of the transactions through review of executed transaction documents and discussions with management.
Perform a detailed accounting analysis for a sample of structured commodity transactions involving significant day 1 profits, working capital arrangements, offtake arrangements and/or commitments.

To assess the appropriateness of the accounting treatment of SCTs, we embedded technical accounting specialists on the audit team to assist in performing an assessment of the treatment applied by management.

Other level 3 financial instruments:
To address the complexities associated with auditing the value of level 3 financial instruments, our team included valuation specialists having significant quantitative and modelling expertise to assist in performing our audit procedures. Our valuation audit procedures included the following control and substantive procedures:
We tested the design and operating effectiveness of the group's valuation controls including the:

Model certification control, which is designed to review a model's theoretical soundness and the appropriateness of its valuation methodology; and
Independent price verification control, which is designed to review the appropriateness of valuation inputs that are not observable and are significant to the financial instrument's valuation.

We performed substantive valuation testing procedures at interim and year-end balance sheet dates, including:

Developing independent estimates, using externally sourced inputs and challenger models to evaluate against management's fair value estimates by evaluating whether the differences between our independent estimates and management's estimates were within a reasonable range;
Evaluating management's valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period; and
Benchmarking management's input assumptions against the expected assumptions of other market participants and observable market data.

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<tr><td>Key observations</td><td>
We reviewed the features of 10 SCTs and determined that the accounting adopted for each of these was appropriate and in accordance with IFRS.

We concluded that management's valuations relating to level 3 instruments were appropriate.

We did not identify any transactions, valuation estimates or accounting entries which were the result of fraudulent misrepresentation of revenue recognition.
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<table>
<tr><th colspan="2">User access management controls relating to financial systems</th></tr>
<tr><th>Key audit matter description</th><th>How the scope of our audit responded to the key audit matter</th></tr>
<tr><td>The group’s financial systems environment is complex, with 107 separate systems scoped as being relevant for the group audit. In addition, during the year, BP changed one of its key IT service providers.

Due to the reliance on financial systems within the group, controls over system user access are critical to maintaining an effective control environment.

As a result of our procedures, we identified a number of deficiencies relating to user access management, both within the group and the group’s IT service organizations (together ‘access deficiencies’). The access deficiencies identified increase the risk that individuals within the group and at service organizations had inappropriate access during the period. The existence of deficiencies during the year and at the year end, and the transition of the main IT service organization from one supplier to another during the year, result in an increased risk that data and reports from the affected systems are not reliable. The issues identified impact all components within the scope of our group audit.

The group put in place a programme of activities to remediate the deficiencies, which extends into 2019. Accordingly, management also identified mitigating and compensating controls, and in particular established controls to analyse, through exploitation analyses, whether inappropriate access had been exploited during the year, working with both the legacy and new IT service organizations.

The user access management controls are pervasive to the group’s operations and accordingly the level of risk ascribed to our work in this area is dependent on the nature and complexity of the control itself and balances within the financial statements the control addresses.</td><td>We obtained an understanding of management’s processes and relevant financial systems and tested the associated general IT controls. This testing led us to identify a number of deficiencies, notably in relation to user access.

In responding to the identified deficiencies in user access we have used our teams of IT and internal control specialists to:

• Test the controls that management has implemented or re-designed in order to remediate the deficiencies;
• Assess and test the alternative or compensating controls that management has identified as mitigating access deficiencies, including the direct assessment of those controls operated by the legacy and new IT service organizations and identified business controls that do not rely on information that is potentially affected by the access deficiencies; and
• Determine the impact that utilizing inappropriate levels of access could feasibly have had on the affected systems including assessing the likelihood of inappropriate user access impacting the financial statements, and testing controls implemented by management to identify instances of the use of inappropriate access, working with both the legacy and new IT service organizations.</td></tr>
<tr><td>Key observations</td><td>Our review of the analysis management performed to identify whether the access deficiencies were exploited during the year did not identify instances where such access had been used inappropriately.

As a result, we were satisfied with the results of the remediation to date and mitigation activities such that we continued to adopt an audit approach which places reliance on the effectiveness of financial controls and which, under our methodology, enables us to apply lower sample sizes in our substantive testing.

Management continues to work, with the support of the new IT service provider, to remediate fully the access deficiencies identified.</td></tr>
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<tr><th colspan="2">Management override of controls</th></tr>
<tr><th>Key audit matter description</th><th>How the scope of our audit responded to the key audit matter</th></tr>
<tr><td>We conducted a risk assessment for management override fraud risks by considering:
• Potential areas where the group's financial statements could be manipulated;
• Pressures or incentives to achieve certain IFRS or non-GAAP measures due to the remuneration arrangements of people in Financial Reporting Oversight Roles (FRORs), including management and senior executives;
• Potential for inappropriate accounting estimates and judgements; and
• Accounting for significant unusual transactions and estimates arising from changes to the business.

Our response to the risk of management override of controls included testing the appropriateness of journal entries recorded in the general ledger. We identified control deficiencies at components where testing was performed and as a result, our audit approach required adjustment. Management remediated the control deficiencies identified where it was possible to do so. Some remediation activity will continue into 2019 and accordingly, management also directed us to other compensating controls which they considered to mitigate the risks, which we subsequently tested. This had a bearing on the allocation of resources in the audit, and the direction of effort of the audit team. Accordingly, we identified this as a key audit matter.</td><td>We tested the relevant primary and, where necessary, compensating controls that management identified as responding to the risk of fraudulent journal entries.

In addition, we have:
• Made inquiries of individuals involved in the financial reporting process about inappropriate or unusual activity relating to the processing of journal entries and other adjustments.
• Identified and tested relevant entity-level controls, in particular those related to the BP Code of Conduct, whistleblowing (BP OpenTalk) and controls monitoring financial reporting processes and financial results.
• Used our data analytics tools to select journal entries and other adjustments made at the end of a reporting period or otherwise having characteristics which are associated with common fraud schemes for testing.
• Tested journal entries and other adjustments recorded in the general ledger throughout the period, with a particular focus on adjustments that occur late in the financial close process.

We have reviewed accounting estimates for bias and evaluated whether the circumstances producing the bias, if any, represent a risk of material misstatement due to fraud. A number of the most significant estimates are covered by the other Key Audit Matters set out above. This assessment included:
• Evaluating whether the judgements and decisions made by management in making the accounting estimates included in the financial statements, even if they are individually reasonable, indicate a possible bias on the part of BP's management that may represent a risk of material misstatement due to fraud; and
• Performing a retrospective review of management judgements and assumptions related to significant accounting estimates reflected in the financial statements of the prior year.

We considered whether there were any significant transactions that are outside the normal course of business, or that otherwise appear to be unusual due to their nature, timing or size.

The risks and responses to the revenue recognition risks within the integrated supply and trading function are set out above.</td></tr>
<tr><td>Key observations</td><td>The nature of the identified deficiencies over journal-entry controls varies from business to business, so there is no single root cause. At the year end:
• In some businesses these operating effectiveness deficiencies were able to be remediated by management and our testing of the remediation concluded it was effective.
• In other businesses the deficiencies could not be quickly remediated and management identified direct and precise compensating controls to mitigate the design deficiencies identified. These compensating controls included low-level analytical reviews (e.g. individual asset reviews), controls over closing balances, period-end analytical review controls, and certain automated business controls. Our testing of these compensating controls concluded that they were, in combination, appropriately designed and implemented and that they were operating effectively for the period.

Our substantive testing of the journal entries and other adjustments, selected through the use of data analytics tools, did not identify any inappropriate items, and accordingly we concluded that there was no evidence of management override.

We did not identify any evidence of overall bias or any significant unusual transactions for which the business rationale (or the lack thereof) of the transaction suggested that it may have been entered into to engage in fraudulent financial reporting or to conceal misappropriation of assets.</td></tr>
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Our application of materiality

We define materiality as the magnitude of misstatement in the financial statements that could reasonably be expected to influence the economic decisions of a reasonably knowledgeable user. We use materiality both in planning the scope of our audit work and in evaluating the results of our work.

Based on our professional judgement, we determined materiality for the financial statements as a whole as follows:

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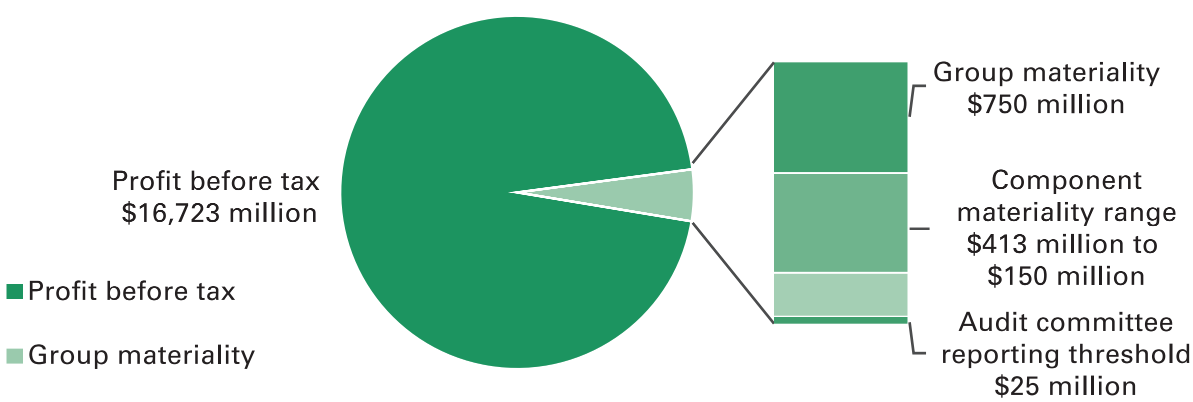
	Group financial statements	Parent company financial statements
Materiality	Materiality has been set at $750 million for the current year. In 2017, the previous auditor used a materiality of $500 million. This reflects BP's financial performance in 2018 and 2017.	Materiality has been set at $1,200 million for the current year. In 2017, the previous auditor used a materiality of $1,300 million.
Basis for determining materiality	We used a number of metrics to determine group materiality, most notably profit before taxation and underlying replacement cost profit before interest and taxation. Our selected materiality figure represents 4.5% of profit before taxation, and 3.2% of underlying replacement cost profit before interest and taxation. In 2017, the previous auditor used 5% of underlying replacement cost profit before interest and taxation to determine materiality.	We determined materiality for our audit of the standalone parent using 1% of net assets.
Rationale for the benchmark applied	We conducted an assessment of which line items we understand to be the most important to investors and analysts by reviewing analyst reports and BP's communications to shareholders and lenders, as well as the communications of peer companies. This assessment resulted in us selecting the financial statement line items above. Profit before tax is the benchmark ordinarily considered by us when auditing listed entities. It provides comparability against other companies across all sectors, but has limitations when auditing companies whose earnings are strongly correlated to commodity prices, which can be volatile from one period to the next, and therefore may not be representative of the volume of transactions and the overall size of the business in the year. Whilst not a GAAP measure, underlying replacement cost profit before interest and tax is one of the key metrics communicated by management in BP's results announcements. It excludes some of the volatility arising from changes in crude oil, gas and product prices as well as "non-operating items" and this was also the key measure applied by the previous auditor when determining materiality in 2017.	The materiality determined for the standalone parent company financial statements exceeds the group materiality as it is determined on a different basis given the nature of the operations. As the company is non-trading and operates primarily as a holding company, we believe the net asset position is the most appropriate benchmark to use. Where there were balances and transactions within the parent company accounts that were within the scope of the audit of the group financial statements, our procedures were undertaken using the lower materiality level applying to the group audit components. It was only for the purposes of testing balances not relevant to the group audit, such as intercompany investment balances, that the higher level of materiality applied in practice.



Performance materiality, which is the value that determines the extent of our audit sampling, has been set at $375 million which is 50% of group materiality (2017 75%). Given overall group materiality is higher in 2018 reflecting the improved results of the business, performance materiality could also be set at a higher level but we judged it to be appropriate to constrain this for 2018 given it is our first year as auditor, which gives a potentially heightened risk of not identifying misstatements due to us having a lower level of knowledge of the business than a recurring auditor would have.

We agreed with the Main Board Audit Committee that we would report to the committee all audit differences in excess of $25 million (2017 $25 million), as well as differences below that threshold that, in our view, warranted reporting on qualitative grounds. We also report to the audit committee on disclosure matters that we identified when assessing the overall presentation of the financial statements.

An overview of the scope of our audit

As a result of the highly disaggregated nature of the group, with operations in over 70 countries through approximately 1,000 components, a significant portion of our audit planning effort was ensuring that the scope of our work is appropriate in addressing the identified risks of material misstatement.

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The factors that we considered when assessing the scope of the BP audit, and the level of work to be performed at the components that are in scope for group reporting purposes, included the following:

- The financial significance of an operating unit to BP's revenue and profit before tax, or PP&E, including consideration of the financial significance of specific account balances or transactions.
- The significance of specific risks relating to an operating unit, history of unusual or complex transactions, identification of significant audit issues or the potential for, or a history of, material misstatements.
- The effectiveness of the control environment and monitoring activities, including entity-level controls.
- The findings, observations and audit differences that we noted as a result of the previous auditor's 2016 and 2017 audit engagements.

To ensure we were able to obtain sufficient, appropriate audit evidence for the purposes of our audit of the financial statements, we performed full scope audit procedures for 108 reporting consolidation units ('cons units' or components) which were selected based on their size or risk characteristics. Our full-scope audits are in the UK, US, Angola, Azerbaijan, Germany and Singapore. One of the full-scope cons units includes the investment in Rosneft, a material associate not controlled by BP.

In addition, we performed audit procedures on specified account balances by local teams for 16 cons units also covering operations in Trinidad & Tobago and Australia. We performed audit procedures on specified account balances by segment teams to component materiality, with certain additional specific procedures performed by local teams, covering an additional 12 cons units.

In our assessment of the residual balances, we have considered in particular the risk that there could be a material misstatement within the large number of geographically dispersed businesses, in particular within the Downstream segment. This assessment included use of our analytic tools to interrogate data, preparation of trend analysis and comparison of business performance to market benchmark prices. We concluded that through this additional risk assessment, we have reduced the audit risk of such a misstatement arising to a sufficiently low level.

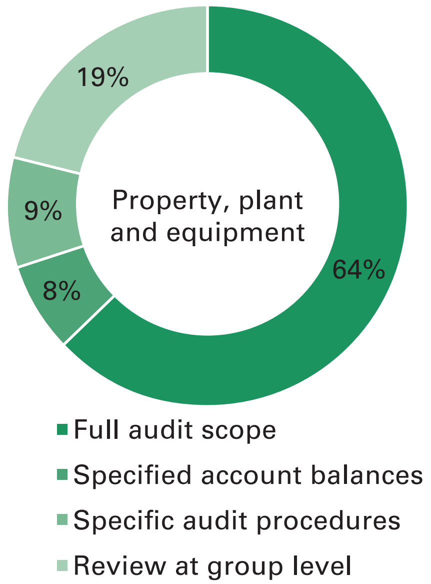
The remaining components are not significant individually and include many small, low risk components and balances. On average, they each represent 0.06% of group revenue and 0.08% of property, plant and equipment. For these components, we performed other procedures, including conducting analytical review procedures, making inquiries, and evaluating and testing management's group-wide controls across a range of locations and segments in order to address the risk of residual misstatement on a segment-wide and component basis.

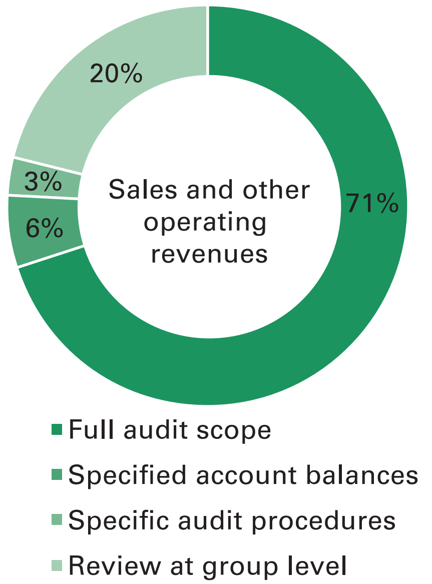
Oversight of component auditors

The group audit team provides direct oversight, review, and coordination of our local audit teams. The group audit team interacted regularly with the local Deloitte teams during each stage of the audit, were responsible for the scope and direction of the audit process and reviewed key working papers. We maintained continuous and open dialogue with our local teams in addition to holding formal meetings quarterly to ensure that we were fully aware of their progress and results of their procedures.

The senior statutory auditor and other group audit partners and staff visited local component teams in all of the locations named above. These visits included attending planning meetings, discussing the audit approach and any issues arising from the component team's work, meetings with local management, and reviewing key audit working papers on higher and significant-risk areas to drive a consistent and high-quality audit.

We were provided with direct access to Rosneft's auditor in order to evaluate their audit work on the financial statements of Rosneft, used as the basis for BP's equity accounting. We held meetings with Rosneft's auditor throughout the year, issued audit instructions to them, reviewed their written clearance reports responding to these instructions and, through our direct access, were able to exercise appropriate supervision and oversight of their audit work. We also tested directly BP's procedures and controls over its accounting for the investment in Rosneft.





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Other information

The directors are responsible for the other information. The other information comprises the information included in the annual report other than the financial statements and our auditor's report thereon.

We have nothing to report in respect of these matters.

Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in our report, we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether there is a material misstatement in the financial statements or a material misstatement of the other information. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact.

In this context, matters that we are specifically required to report to you as uncorrected material misstatements of the other information include where we conclude that:

- *Fair, balanced and understandable* - the statement given by the directors that they consider the annual report and financial statements taken as a whole is fair, balanced and understandable and provides the information necessary for shareholders to assess the group's position and performance, business model and strategy, is materially inconsistent with our knowledge obtained in the audit; or
- *Audit committee reporting* - the section describing the work of the audit committee does not appropriately address matters communicated by us to the audit committee; or
- *Directors' statement of compliance with the UK Corporate Governance Code* - the parts of the directors' statement required under the Listing Rules relating to the company's compliance with the UK Corporate Governance Code containing provisions specified for review by the auditor in accordance with Listing Rule 9.8.10R(2) do not properly disclose a departure from a relevant provision of the UK Corporate Governance Code.

Responsibilities of directors

As explained more fully in the directors' responsibilities statement, the directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view, and for such internal control as the directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the directors are responsible for assessing the group's and the parent company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the group or the parent company or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of a reasonably knowledgeable user, taken on the basis of these financial statements.

Details of the extent to which the audit was considered capable of detecting irregularities, including fraud are set out below.

A further description of our responsibilities for the audit of the financial statements is located on the FRC's website at: *frc.org.uk/auditorsresponsibilities.* This description forms part of our auditor's report.

Extent to which the audit was considered capable of detecting irregularities, including fraud

We identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and then design and perform audit procedures responsive to those risks, including obtaining audit evidence that is sufficient and appropriate to provide a basis for our opinion.

Identifying and assessing potential risks related to irregularities

In identifying and assessing risks of material misstatement in respect of irregularities, including fraud and non-compliance with laws and regulations, our procedures included the following:

- Meeting throughout the year with the group head of ethics and compliance and reviewing BP's internal ethics and compliance reporting summaries, including concerning investigations;
- Enquiring of management, internal audit, and the audit committee, including obtaining and reviewing supporting documentation, concerning the group's policies and procedures relating to:
  - identifying, evaluating and complying with laws and regulations and whether they were aware of any instances of non-compliance
  - detecting and responding to the risks of fraud and whether they have knowledge of any actual, suspected or alleged fraud
  - the internal controls established to mitigate risks related to fraud or non-compliance with laws and regulations;
- Discussing among the engagement team regarding how and where fraud might occur in the financial statements and any potential indicators of fraud. The engagement team includes audit partners and staff who have extensive experience of working with companies in the same sectors as BP operates, and this experience was relevant to the discussion about where fraud risks may arise. The discussions also involved fraud experts from Deloitte's forensic accounting function in the Corporate Finance service line, who advised the engagement team of fraud schemes that had arisen in similar sectors and industries and participated in the initial fraud risk assessment brainstorming discussions; and
- Obtaining an understanding of the legal and regulatory frameworks that the group operates in, focusing on those laws and regulations that we determined had a direct effect on the financial statements or that had a fundamental effect on the operations of the group. These include

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the UK Companies Act, UK Corporate Governance Code, IFRS as issued by the IASB and adopted by the EU, FRS 101, US Securities Exchange Act 1934 and relevant SEC regulations, as well as laws and regulations prevailing in each country in which we identified a full-scope component. In addition, we considered compliance with terms of the group's operating licence / regulatory solvency requirements / environmental regulations when assessing the group's ability to continue as a going concern.

Audit response to risks identified

As a result of performing the above, we did not identify any key audit matters related to the potential risk of non-compliance with laws and regulations. We did identify two key audit matters relating to fraud risks, as described above.

Our procedures to respond to risks identified included the following:

- Reviewing the financial statement disclosures and testing supporting documentation to assess compliance with relevant laws and regulations discussed above;
- Enquiring of management, the audit committee and legal counsel concerning actual and potential litigation and claims;
- Performing analytical procedures to identify any unusual or unexpected relationships that may indicate risks of material misstatement due to fraud;
- Reading minutes of meetings of those charged with governance, reviewing internal audit reports and reviewing correspondence with HMRC; and
- In addressing the risk of fraud through management override of controls, testing the appropriateness of journal entries and other adjustments; assessing whether the judgements made in making accounting estimates are indicative of a potential bias; and evaluating the business rationale of any significant transactions that are unusual or outside the normal course of business.

We also communicated relevant identified laws and regulations and potential fraud risks to all engagement team members, including internal specialists and significant component audit teams, and remained alert to any indications of fraud or non-compliance with laws and regulations throughout the audit.

Report on other legal and regulatory requirements

Opinions 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.

In our opinion, based on the work undertaken in the course of the audit:

- 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; and
- The strategic report and the directors' report have been prepared in accordance with applicable legal requirements.

In the light of the knowledge and understanding of the group and the parent company and their environment obtained in the course of the audit, we have not identified any material misstatements in the strategic report or the directors' report.

Matters on which we are required to report by exception

Adequacy of explanations received and accounting records

Under the Companies Act 2006 we are required to report to you if, in our opinion:

- We have not received all the information and explanations we require for our audit; or
- 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 are not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

Directors' remuneration

Under the Companies Act 2006 we are also required to report if in our opinion certain disclosures of directors' remuneration have not been made or the part of the directors' remuneration report to be audited is not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

Other matters

Auditor tenure

The board appointed Deloitte as the company's auditor with effect from 29 March 2018 to fill the vacancy arising from the resignation of the previous auditor. On 21 May 2018, shareholders resolved at the annual general meeting to appoint Deloitte as auditor from the conclusion of the meeting until the conclusion of the annual general meeting to be held in 2019 and authorized the directors to set the audit fees.

The first accounting period we audited was the 12 months ended 31 December 2018. In 2017, we commenced our audit planning procedures. The period of total uninterrupted engagement including previous renewals and reappointments of the firm is accordingly one year.

Consistency of the audit report with the additional report to the audit committee

Our audit opinion is consistent with the additional report to the audit committee we are required to provide in accordance with ISAs (UK).

Use of our report

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.

Douglas King FCA (Senior statutory auditor)
For and on behalf of Deloitte LLP
Statutory Auditor
London, United Kingdom
29 March 2019

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

Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

To the shareholders and board of directors of BP p.l.c.

Opinion on the financial statements

We have audited the accompanying group balance sheet of BP p.l.c. and subsidiaries (the Company) as at 31 December 2018, the related group income statement, statements of comprehensive income and changes in equity, and group cash flow statement, for the year ended 31 December 2018, and the related notes (collectively referred to as the 'financial statements'). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of 31 December 2018, and the results of its operations and its cash flows for the year ended 31 December 2018, in conformity with International Financial Reporting Standards (IFRS) as adopted by the European Union and IFRS as issued by the International Accounting Standards Board.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of 31 December 2018, based on criteria established in the *UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting* relating to internal control over financial reporting and our report dated 29 March 2019 expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ Deloitte LLP

London
United Kingdom
29 March 2019

The first accounting period we audited was the 12 months ended 31 December 2018. In 2017, we commenced our audit planning procedures.

Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

To the shareholders and board of directors of BP p.l.c.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of BP p.l.c. and subsidiaries (the Company) as at 31 December 2018, based on the criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting relating to internal control over financial reporting (UK FRC Guidance). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of 31 December 2018, based on the criteria established in the UK FRC Guidance.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as at and for the year ended 31 December 2018, of the Company and our report dated 29 March 2019, expressed an unqualified opinion on those financial statements.

As described in Management's report on internal control over financial reporting on page 301, management excluded from its assessment the internal control over financial reporting at Petrohawk Energy Corporation, which was acquired on 31 October 2018 and whose financial statements constitute 10.3% and 4.0% of net and total assets, respectively, 0.2% of total revenues and other income, and 0.05% of profit for the year of the consolidated financial statement amounts as at and for the year ended 31 December 2018. Accordingly, our audit did not include the internal control over financial reporting at Petrohawk Energy Corporation.

Basis for opinion

The Company'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 over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and limitations of internal control over financial reporting

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.

/s/ Deloitte LLP
London, United Kingdom
29 March 2019

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 29 March 2019, relating to the consolidated financial statements of BP p.l.c. (the 'company'), and the effectiveness of the company's internal control over financial reporting, appearing in the Annual Report on Form 20-F of the company for the year ended 31 December 2018, in the following Registration Statements:

Registration Statements on Form F-3 (File Nos. 333-226485, 333-226485-01 and 333-226485-02) of BP p.l.c., BP Capital Markets p.l.c. and BP Capital Markets America Inc.; 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, 333-207189, 333-210316, 333-210318) of BP p.l.c.

/s/ Deloitte LLP
London, United Kingdom
29 March 2019

Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

To the shareholders and board of directors of BP p.l.c.

Opinion on the financial statements

We have audited the accompanying group balance sheets of BP p.l.c. (the Company) as of 31 December 2017, 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 two years in the period ended 31 December 2017, and the related notes (collectively referred to as the "group financial statements"). In our opinion, the group financial statements present fairly, in all material respects, the financial position of BP p.l.c. at 31 December 2017 and the results of its operations and its cash flows for each of the two years in the period ended 31 December 2017, in conformity with International Financial Reporting Standards (IFRS) as adopted by the European Union and IFRS as issued by the International Accounting Standards Board.

Basis for opinion

These financial statements are the responsibility of BP p.l.c.'s management. Our responsibility is to express an opinion on these financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to BP p.l.c. in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP
We served as the Company's auditor from 1909 to 2018.
London, United Kingdom
29 March 2018

Note that the report set out above is included for the purposes of BP p.l.c.'s Annual Report on Form 20-F for 2018 only and does not form part of BP p.l.c.'s Annual Report and Accounts for 2017.

1. The maintenance and integrity of the BP p.l.c. web site is the responsibility of BP p.l.c.; 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.

Group income statement

For the year ended 31 December

	Note	2018	2017	2016
				$ million
Sales and other operating revenues	5	**298,756**	240,208	183,008
Earnings from joint ventures – after interest and tax	16	**897**	1,177	966
Earnings from associates – after interest and tax	17	**2,856**	1,330	994
Interest and other income	7	**773**	657	506
Gains on sale of businesses and fixed assets	4	**456**	1,210	1,132
Total revenues and other income		**303,738**	244,582	186,606
Purchases	19	**229,878**	179,716	132,219
Production and manufacturing expenses[a]		**23,005**	24,229	29,077
Production and similar taxes	5	**1,536**	1,775	683
Depreciation, depletion and amortization	5	**15,457**	15,584	14,505
Impairment and losses on sale of businesses and fixed assets	4	**860**	1,216	(1,664)
Exploration expense	8	**1,445**	2,080	1,721
Distribution and administration expenses		**12,179**	10,508	10,495
Profit (loss) before interest and taxation		**19,378**	9,474	(430)
Finance costs[a]	7	**2,528**	2,074	1,675
Net finance expense relating to pensions and other post-retirement benefits	24	**127**	220	190
Profit (loss) before taxation		**16,723**	7,180	(2,295)
Taxation[a]	9	**7,145**	3,712	(2,467)
Profit (loss) for the year		**9,578**	3,468	172
Attributable to				
BP shareholders		**9,383**	3,389	115
Non-controlling interests		**195**	79	57
		9,578	3,468	172
Earnings per share				
Profit (loss) for the year attributable to BP shareholders				
Per ordinary share (cents)				
Basic	11	**46.98**	17.20	0.61
Diluted	11	**46.67**	17.10	0.60
Per ADS (dollars)				
Basic	11	**2.82**	1.03	0.04
Diluted	11	**2.80**	1.03	0.04

[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	**2018**	2017	2016
Profit (loss) for the year		**9,578**	3,468	172
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**(3,771)**	1,986	254
Exchange (gains) losses on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**—**	(120)	30
Available-for-sale investments		**—**	14	1
Cash flow hedges marked to market	30	**(126)**	197	(639)
Cash flow hedges reclassified to the income statement	30	**120**	116	196
Cash flow hedges reclassified to the balance sheet	30	**—**	112	81
Costs of hedging marked to market	30	**(244)**	—	—
Costs of hedging reclassified to the income statement	30	**58**	—	—
Share of items relating to equity-accounted entities, net of tax	16, 17	**417**	564	833
Income tax relating to items that may be reclassified	9	**4**	(196)	13
		(3,542)	2,673	769
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	24	**2,317**	3,646	(2,496)
Cash flow hedges that will subsequently be transferred to the balance sheet	30	**(37)**	—	—
Income tax relating to items that will not be reclassified	9	**(718)**	(1,303)	739
		1,562	2,343	(1,757)
Other comprehensive income		**(1,980)**	5,016	(988)
Total comprehensive income		**7,598**	8,484	(816)
Attributable to				
BP shareholders		**7,444**	8,353	(846)
Non-controlling interests		**154**	131	30
		7,598	8,484	(816)

[a] See Note 32 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 31 December 2017	**46,122**	**(16,958)**	**(5,156)**	**(743)**	**75,226**	**98,491**	**1,913**	**100,404**
Adjustment on adoption of IFRS 9, net of tax	**—**	**—**	**—**	**(54)**	**(126)**	**(180)**	**—**	**(180)**
At 1 January 2018	**46,122**	**(16,958)**	**(5,156)**	**(797)**	**75,100**	**98,311**	**1,913**	**100,224**
Profit (loss) for the year	**—**	**—**	**—**	**—**	**9,383**	**9,383**	**195**	**9,578**
Other comprehensive income	**—**	**—**	**(3,746)**	**(216)**	**2,023**	**(1,939)**	**(41)**	**(1,980)**
Total comprehensive income	**—**	**—**	**(3,746)**	**(216)**	**11,406**	**7,444**	**154**	**7,598**
Dividends[b]	**—**	**—**	**—**	**—**	**(6,699)**	**(6,699)**	**(170)**	**(6,869)**
Cash flow hedges transferred to the balance sheet, net of tax	**—**	**—**	**—**	**26**	**—**	**26**	**—**	**26**
Repurchase of ordinary share capital	**—**	**—**	**—**	**—**	**(355)**	**(355)**	**—**	**(355)**
Share-based payments, net of tax	**230**	**1,191**	**—**	**—**	**(718)**	**703**	**—**	**703**
Share of equity-accounted entities' changes in equity, net of tax	**—**	**—**	**—**	**—**	**14**	**14**	**—**	**14**
Transactions involving non-controlling interests, net of tax	**—**	**—**	**—**	**—**	**—**	**—**	**207**	**207**
At 31 December 2018	**46,352**	**(15,767)**	**(8,902)**	**(987)**	**78,748**	**99,444**	**2,104**	**101,548**
At 1 January 2017	46,122	(18,443)	(6,878)	(1,153)	75,638	95,286	1,557	96,843
Profit (loss) for the year	—	—	—	—	3,389	3,389	79	3,468
Other comprehensive income	—	—	1,722	410	2,832	4,964	52	5,016
Total comprehensive income	—	—	1,722	410	6,221	8,353	131	8,484
Dividends[b]	—	—	—	—	(6,153)	(6,153)	(141)	(6,294)
Repurchase of ordinary share capital	—	—	—	—	(343)	(343)	—	(343)
Share-based payments, net of tax	—	1,485	—	—	(798)	687	—	687
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	215	215	—	215
Transactions involving non-controlling interests, net of tax	—	—	—	—	446	446	366	812
At 31 December 2017	46,122	(16,958)	(5,156)	(743)	75,226	98,491	1,913	100,404
At 1 January 2016	43,902	(19,964)	(7,267)	(823)	81,368	97,216	1,171	98,387
Profit (loss) for the year	—	—	—	—	115	115	57	172
Other comprehensive income	—	—	389	(330)	(1,020)	(961)	(27)	(988)
Total comprehensive income	—	—	389	(330)	(905)	(846)	30	(816)
Dividends[b]	—	—	—	—	(4,611)	(4,611)	(107)	(4,718)
Share-based payments, net of tax	2,220	1,521	—	—	(750)	2,991	—	2,991
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	106	106	—	106
Transactions involving non-controlling interests, net of tax	—	—	—	—	430	430	463	893
At 31 December 2016	46,122	(18,443)	(6,878)	(1,153)	75,638	95,286	1,557	96,843

[a] See Note 32 for further information.

[b] See Note 10 for further information.

Group balance sheet

At 31 December	Note	2018	$ million 2017
Non-current assets			
Property, plant and equipment	12	**135,261**	129,471
Goodwill	14	**12,204**	11,551
Intangible assets	15	**17,284**	18,355
Investments in joint ventures	16	**8,647**	7,994
Investments in associates	17	**17,673**	16,991
Other investments	18	**1,341**	1,245
Fixed assets		**192,410**	185,607
Loans		**637**	646
Trade and other receivables	20	**1,834**	1,434
Derivative financial instruments	30	**5,145**	4,110
Prepayments		**1,179**	1,112
Deferred tax assets	9	**3,706**	4,469
Defined benefit pension plan surpluses	24	**5,955**	4,169
		210,866	201,547
Current assets			
Loans		**326**	190
Inventories	19	**17,988**	19,011
Trade and other receivables	20	**24,478**	24,849
Derivative financial instruments	30	**3,846**	3,032
Prepayments		**963**	1,414
Current tax receivable		**1,019**	761
Other investments	18	**222**	125
Cash and cash equivalents	25	**22,468**	25,586
		71,310	74,968
Total assets		**282,176**	276,515
Current liabilities			
Trade and other payables	22	**46,265**	44,209
Derivative financial instruments	30	**3,308**	2,808
Accruals		**4,626**	4,960
Finance debt	26	**9,373**	7,739
Current tax payable		**2,101**	1,686
Provisions	23	**2,564**	3,324
		68,237	64,726
Non-current liabilities			
Other payables	22	**13,830**	13,889
Derivative financial instruments	30	**5,625**	3,761
Accruals		**575**	505
Finance debt	26	**56,426**	55,491
Deferred tax liabilities	9	**9,812**	7,982
Provisions	23	**17,732**	20,620
Defined benefit pension plan and other post-retirement benefit plan deficits	24	**8,391**	9,137
		112,391	111,385
Total liabilities		**180,628**	176,111
Net assets		**101,548**	100,404
Equity			
BP shareholders' equity	32	**99,444**	98,491
Non-controlling interests	32	**2,104**	1,913
Total equity	32	**101,548**	100,404

Helge Lund Chairman
R W Dudley Group chief executive
29 March 2019

Group cash flow statement

For the year ended 31 December — $ million

	Note	2018	2017	2016
Operating activities				
Profit (loss) before taxation		**16,723**	7,180	(2,295)
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities				
Exploration expenditure written off	8	**1,085**	1,603	1,274
Depreciation, depletion and amortization	5	**15,457**	15,584	14,505
Impairment and (gain) loss on sale of businesses and fixed assets	4	**404**	6	(2,796)
Earnings from joint ventures and associates		**(3,753)**	(2,507)	(1,960)
Dividends received from joint ventures and associates		**1,535**	1,253	1,105
Interest receivable		**(468)**	(304)	(200)
Interest received		**348**	375	267
Finance costs	7	**2,528**	2,074	1,675
Interest paid		**(1,928)**	(1,572)	(1,137)
Net finance expense relating to pensions and other post-retirement benefits	24	**127**	220	190
Share-based payments		**690**	661	779
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	24	**(386)**	(394)	(467)
Net charge for provisions, less payments		**986**	2,106	4,487
(Increase) decrease in inventories		**672**	(848)	(3,681)
(Increase) decrease in other current and non-current assets		**(2,858)**	(4,848)	(1,172)
Increase (decrease) in other current and non-current liabilities		**(2,577)**	2,344	1,655
Income taxes paid		**(5,712)**	(4,002)	(1,538)
Net cash provided by operating activities		**22,873**	18,931	10,691
Investing activities				
Expenditure on property, plant and equipment, intangible and other assets		**(16,707)**	(16,562)	(16,701)
Acquisitions, net of cash acquired	3	**(6,986)**	(327)	(1)
Investment in joint ventures		**(382)**	(50)	(50)
Investment in associates		**(1,013)**	(901)	(700)
Total cash capital expenditure		**(25,088)**	(17,840)	(17,452)
Proceeds from disposals of fixed assets	4	**940**	2,936	1,372
Proceeds from disposals of businesses, net of cash disposed	4	**1,911**	478	1,259
Proceeds from loan repayments		**666**	349	68
Net cash used in investing activities		**(21,571)**	(14,077)	(14,753)
Financing activities				
Repurchase of shares		**(355)**	(343)	—
Proceeds from long-term financing		**9,038**	8,712	12,442
Repayments of long-term financing		**(7,210)**	(6,276)	(6,685)
Net increase (decrease) in short-term debt		**1,317**	(158)	51
Net increase (decrease) in non-controlling interests		**—**	1,063	887
Dividends paid				
BP shareholders	10	**(6,699)**	(6,153)	(4,611)
Non-controlling interests		**(170)**	(141)	(107)
Net cash provided by (used in) financing activities		**(4,079)**	(3,296)	1,977
Currency translation differences relating to cash and cash equivalents		**(330)**	544	(820)
Increase (decrease) in cash and cash equivalents		**(3,107)**	2,102	(2,905)
Cash and cash equivalents at beginning of year[a]		**25,575**	23,484	26,389
Cash and cash equivalents at end of year		**22,468**	25,586	23,484

[a] See Note 1 for further information.

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 BP p.l.c and its subsidiaries (collectively referred to as BP or the group) for the year ended 31 December 2018 were approved and signed by the group chief executive and chairman on 29 March 2019 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 as applicable to companies reporting under IFRS. 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 2018. The accounting policies that follow have been consistently applied to all years presented, except where otherwise indicated.

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 consolidated 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 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 the investment in Rosneft; oil and natural gas accounting, including the estimation of reserves; the recoverability of asset carrying values; derivative financial instruments; provisions and contingencies; and pensions and other post-retirement benefits. Where an estimate has a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year this is specifically noted within the boxed text. The group no longer considers the recoverability of trade receivables to represent one of its significant accounting judgements following the adoption of IFRS 9 'Financial Instruments' and resulting recognition of expected credit losses, see Impact of new International Financial Reporting Standards for more information. The group does not consider income taxes to represent a significant estimate or judgement for 2018, see Income taxes for more information.

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 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

Business combinations and goodwill

Business combinations are accounted for using the acquisition method. The identifiable assets acquired and liabilities assumed are recognized at their fair values at the acquisition date.

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. See Note 14 for further information.

Goodwill may 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. Any such goodwill is recorded within the corresponding investment in joint ventures and associates.

Goodwill may also arise upon acquisition of interests in joint operations that meet the definition of a business. The amount of goodwill separately recognized is the excess of the consideration transferred over the group's share of the net fair value of the identifiable assets and liabilities.

Interests in joint arrangements

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

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

Significant judgement: investment in Rosneft

Judgement is required in assessing the level of control or influence over another entity in which the group holds an interest. For BP, the judgement that the group has significant influence over Rosneft Oil Company (Rosneft), a Russian oil and gas company is significant. As a consequence of this judgement, BP uses the equity method of accounting for its investment and BP's share of Rosneft's oil and natural gas reserves is included in the group's estimated net proved reserves of equity-accounted entities. If significant influence was not present, the investment would be accounted for as an investment in an equity instrument measured at fair value as described under 'Financial assets' below and no share of Rosneft's oil and natural gas reserves would be reported.

Significant influence is defined in IFRS as the power to participate in the financial and operating policy decisions of the investee but is not control or joint control of those policies. Significant influence is presumed when an entity owns 20% or more of the voting power of the investee. Significant influence is presumed not to be present when an entity owns less than 20% of the voting power of the investee.

BP owns 19.75% of the voting shares of Rosneft. The Russian federal government, through its investment company JSC Rosneftegaz, owned 50% plus one share of the voting shares of Rosneft at 31 December 2018. 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 chairman of the Rosneft board's Strategic Planning Committee. A second BP-nominated director, Guillermo Quintero, has been a member of the Rosneft board and its HR and Remuneration Committee since 2015. BP also holds the voting rights at general meetings of shareholders conferred by its 19.75% stake in Rosneft. BP's management consider, therefore, that the group has significant influence over Rosneft, as defined by IFRS.

The equity method of accounting

Under the equity method, an 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 in the accounting policies used by the equity-accounted entity and those used by BP, 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 there is objective evidence that the investment is impaired. If any such objective evidence 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.

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 recognized in a separate component of equity and reported in other 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 reported in other comprehensive income if the borrowings form part of the net investment in the subsidiary, joint venture or associate. On disposal or for certain partial disposals of a non-US dollar functional currency subsidiary, joint venture or associate, the related accumulated exchange gains and losses recognized in equity are reclassified from equity 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.

Significant 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.

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

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 are carried initially at cost unless acquired as part of a business combination. Any such asset is measured at fair value at the date of the business combination 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 fifteen years. Computer software costs generally have a useful life of three to five years.

The expected useful lives of assets and the amortization method are reviewed on an annual basis and, if necessary, changes in useful lives or the amortization method 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. 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.

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 or appraisal work in the area, remain capitalized on the balance sheet as long as such work is under way or firmly planned.

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 judgement: oil and natural gas accounting

Judgement is required to determine whether it is appropriate to continue to carry costs associated with exploration wells and exploratory-type stratigraphic test wells on the balance sheet. This includes costs relating to exploration licences or leasehold property acquisitions. It is not unusual to have such costs 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 circumstances that indicate 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 that were scheduled to expire at the end of 2013 and some with terms that 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. The carrying amount of capitalized costs is included in Note 8.

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

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, directly attributable general or specific 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. 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 12 and Note 5 respectively.

Estimates of oil and natural gas reserves determined by applying US Securities and Exchange Commission regulations including the determination of prices using 12-month historical data 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.

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 210, which is unaudited. Details on BP's proved reserves and production compliance and governance processes are provided on page 286. The 2018 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 210.

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 and depreciation method of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives or the depreciation method 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.

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.

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

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 that are not reflected in the discount rate and are discounted to their present value typically 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 CGUs 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.

Significant judgements and estimates: 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 the effects of inflation and deflation on operating expenses, discount rates, production profiles, reserves and resources, and future commodity prices, including the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas and refined products. Judgement is required when determining the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment testing purposes. For example, certain oil and gas properties with shared infrastructure may be grouped together to form a single CGU. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing. See Note 14 for details on how these groupings have been determined in relation to the impairment testing of goodwill.

As disclosed above, the recoverable amount of an asset is the higher of its value in use and its fair value less costs of disposal. Fair value less costs of disposal may be determined based on expected sales proceeds or similar recent market transaction data or, where recent market transactions 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, estimates 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.

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 12, Note 14 and Note 15.

The estimates for assumptions made in impairment tests in 2018 relating to discount rates, oil and gas properties and oil and gas prices are discussed below. Changes in the economic environment or other facts and circumstances may necessitate revisions to these assumptions and could result in a material change to the carrying values of the group's assets within the next financial year.

Discount rates

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the cash-generating unit. Value-in-use calculations are typically discounted using a pre-tax discount rate based upon the cost of funding the group derived from an established model, adjusted to a pre-tax basis. Fair value less costs of disposal calculations use the post-tax discount rate.

The discount rates applied in impairment tests are reassessed each year. In 2018 the post-tax discount rate was 6% (2017 6%) and the pre-tax discount rate was 9% (2017 9%). Where the cash-generating unit is located in a country which is judged to be higher risk an additional 2% premium was added to the discount rate (2017 2%). The judgement of classifying a country as higher risk takes into account various economic and geopolitical factors.

Oil and natural gas properties

For oil and natural gas properties, expected future cash flows are estimated using management's best estimate of future oil and natural gas prices and production and reserves volumes. 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.

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

Oil and gas prices

The long-term price assumptions used to determine recoverable amount based on value-in-use impairment tests from 2024 onwards are derived from $75 per barrel for Brent and $4/mmBtu for Henry Hub, both in 2015 prices, inflated for the remaining life of the asset (2017 $75 per barrel and $4/mmBtu, both in 2015 prices, from 2023 onwards).

The price assumptions used for the five-year period to 2023 have been set such that there is a gradual transition from current market prices to the long-term price assumptions as noted above, with the rate of increase reducing in the later years.

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

Oil prices rebounded in 2018 in the face of cooperative production restraint from OPEC and some non-OPEC producers, but weakened late in the year as production restraint eased and US supply recorded record growth. BP's long-term assumption for oil prices is higher than recent market prices, reflecting the judgement that recent prices are not consistent with the market being able to produce sufficient oil to meet global demand sustainably in the longer term, especially given the financial requirements of key low-cost oil producing economies.

US gas prices remained relatively low for much of 2018, before increasing temporarily in the final quarter due to a combination of low storage and cold weather. Strong growth of low-cost supply helped to moderate prices through much of the year. BP's long-term price assumption for US gas is higher than recent market prices as US gas demand is expected to grow strongly, both domestic demand as well as exports of liquefied natural gas, absorbing the lowest cost resources from the sweet spots, and forcing producers to go to more expensive/drier gas, as well as requiring increased investment in infrastructure.

Oil and natural gas reserves

In addition to oil and gas prices, significant technical and commercial assessments are required to determine the group's estimated oil and natural gas reserves. Reserves estimates are regularly reviewed and updated. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity and drilling of new wells 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.

Reserves assumptions for value-in-use and fair value tests reflect the reserves and resources that management currently intend to develop. The recoverable amount of oil and gas properties is determined using a combination of inputs including reserves, resources and production volumes. Risk factors may be applied to reserves and resources which do not meet the criteria to be treated as proved.

The interdependency of these inputs, risk factors and the wide diversity of our oil and gas properties limits the practicability of estimating the probability or extent to which the overall recoverable amount is impacted by changes to one or more of the underlying assumptions. The recoverable amount of oil and gas properties is primarily sensitive to changes in the long-term oil and gas price assumptions. Management do not expect a change in these long-term price assumptions within the next financial year that would result in a material impairment charge. However, sensitivity analysis may be performed if a specific oil and gas property is identified to have low headroom above its carrying amount. In 2018, the group identified oil and gas properties with carrying amounts totalling $22,000 million where the headroom, as at the dates of the last impairment test performed on those assets, was less than or equal to 20% of the carrying value, including $1,345 million in relation to equity-accounted entities. A change in the discount rate, reserves, resources or the oil and gas price assumptions in the next financial year may result in the recoverable amount of one or more of these assets falling below the current carrying amount.

Goodwill

Irrespective of whether there is any indication of impairment, BP is required to test annually for impairment of goodwill acquired in business combinations. The group carries goodwill of approximately $12.2 billion on its balance sheet (2017 $11.6 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. If there are low oil or natural gas prices for an extended period or the long-term price outlook weakens, the group may need to recognize goodwill impairment charges against its Upstream segment goodwill. Sensitivities relating to impairment testing of goodwill in the Upstream segment are provided in Note 14.

Inventories

Inventories, other than inventories held for short-term 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 short-term 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

Agreements under which payments are made to owners in return for the right to use a specific asset are accounted for as leases. Leases that transfer substantially all the risks and rewards of ownership are recognized as finance leases. All other leases are accounted for as operating 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 except where capitalized as exploration or appraisal expenditure. See significant accounting policy: Exploration and appraisal expenditure.

Financial assets

Financial assets are recognized initially at fair value, normally being the transaction price. In the case of financial assets not at fair value through profit or loss, directly attributable transaction costs are also included. The subsequent measurement of financial assets depends on their classification, as set out below. The group derecognizes financial assets when the contractual rights to the cash flows expire or the financial asset is transferred to a third party. This includes the derecognition of receivables for which discounting arrangements are entered into.

From 1 January 2018, the group classifies its financial asset debt instruments as measured at amortized cost, fair value through other comprehensive income or fair value through profit or loss. The classification depends on the business model for managing the financial assets and the contractual cash flow characteristics of the financial asset.

Financial assets measured at amortized cost

Financial assets are classified as measured at amortized cost when they are held in a business model the objective of which is to collect contractual cash flows and the contractual cash flows represent solely payments of principal and interest. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in profit or loss when the assets are derecognized or impaired and when interest is recognized using the effective interest method. This category of financial assets includes trade and other receivables.

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

Financial assets measured at fair value through other comprehensive income

Financial assets are classified as measured at fair value through other comprehensive income when they are held in a business model the objective of which is both to collect contractual cash flows and sell the financial assets, and the contractual cash flows represent solely payments of principal and interest. The group does not have any financial assets classified in this category.

Financial assets measured at fair value through profit or loss

Financial assets are classified as measured at fair value through profit or loss when the asset does not meet the criteria to be measured at amortized cost or fair value through other comprehensive income. Such assets 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 included in this category.

Investments in equity instruments

Investments in equity instruments are subsequently measured at fair value through profit or loss unless an election is made on an instrument-by-instrument basis to recognise fair value gains and losses in other comprehensive income.

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.

Cash equivalents

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 generally have a maturity of three months or less from the date of acquisition. Cash equivalents are classified as financial assets measured at amortized cost or fair value through profit or loss.

Impairment of financial assets measured at amortized cost

The group assesses on a forward looking basis the expected credit losses associated with financial assets classified as measured at amortized cost at each balance sheet date. Expected credit losses are measured based on the maximum contractual period over which the group is exposed to credit risk. Since this is typically less than 12 months there is no significant difference between the measurement of 12-month and lifetime expected credit losses for the group's in-scope financial assets. The measurement of expected credit losses is a function of the probability of default, loss given default and exposure at default. The expected credit loss is estimated as the difference between the asset's carrying amount and the present value of the future cash flows the group expects to receive discounted at the financial asset's original effective interest rate. The carrying amount of the asset is adjusted, with the amount of the impairment gain or loss recognized in the income statement.

A financial asset or group of financial assets classified as measured at amortized cost is considered to be credit-impaired if there is reasonable and supportable evidence that one or more events that have a detrimental impact on the estimated future cash flows of the financial asset (or group of financial assets) have occurred. Financial assets are written off where the group has no reasonable expectation of recovering amounts due.

Financial liabilities

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

Financial liabilities measured at fair value through profit or loss

Financial liabilities that meet the definition of held for trading are classified as measured at fair value through profit or loss. Such liabilities 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 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 directly attributable transaction costs. For interest-bearing loans and borrowings this is typically equivalent to 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.

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 at inception of a contract are recognized immediately in the income statement.

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

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, the existence at inception of an economic relationship and subsequent measurement of the hedging instrument's effectiveness in offsetting the exposure to changes in the hedged item's fair value or cash flows attributable to the hedged risk, the hedge ratio and sources of hedge ineffectiveness. 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, where it offsets. The group applies fair value hedge accounting when hedging interest rate risk and certain currency risks on fixed rate finance debt.

Fair value hedge accounting is discontinued only when the hedging relationship or a part thereof ceases to meet the qualifying criteria. This includes when the risk management objective changes or when the hedging instrument is sold, terminated or exercised. The accumulated adjustment to the carrying amount of a hedged item at such time is then amortized prospectively to profit or loss as finance interest expense over the hedged item's remaining period to maturity.

Cash flow hedges

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

Where the hedged item is a highly probably forecast transaction that results in the recognition of 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 transferred 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.

Cash flow hedge accounting is discontinued only when the hedging relationship or a part thereof ceases to meet the qualifying criteria. This includes when the designated hedged forecast transaction or part thereof is no longer considered to be highly probable to occur, or when the hedging instrument is sold, terminated or exercised without replacement or rollover. When cash flow hedge accounting is discontinued amounts previously recognized within other comprehensive income remain in equity until the forecast transaction occurs and are reclassified to profit or loss or transferred to the initial carrying amount of a non-financial asset or liability as above. If the forecast transaction is no longer expected to occur, amounts previously recognized within other comprehensive income will be immediately reclassified to profit or loss.

Costs of hedging

Time value of options and the foreign currency basis spread of cross-currency interest rate swaps are excluded from hedge designations and accounted for as costs of hedging. Changes in fair value of the time-value component of option contracts and the foreign currency basis spread of cross-currency interest rate swaps are recognized in other comprehensive income to the extent that they relate to the hedged item. For transaction-related hedged items, the amount recognized in other comprehensive income is reclassified to profit or loss when the hedged transaction affects profit or loss. For time-period related hedged items, the amount recognized in other comprehensive income is amortized to profit or loss on a straight line over the term of the hedging relationship.

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 judgement and estimate: derivative financial instruments

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 historical and long-term pricing relationships. Price volatility is also an input for options models. Changes in the key assumptions, in particular price curves, could have a material impact on the carrying amounts of derivative assets and liabilities in the next financial year. The impact on net assets and the Group income statement would be limited as a result of offsetting movements on derivative assets and liabilities. For more information see Note 30.

In some cases, judgement is required to determine whether contracts to buy or sell commodities meet the definition of a derivative. In particular longer-term contracts to buy and sell LNG are not considered to meet the definition as they are not considered capable of being net settled due to a lack of liquidity in the LNG market and so are accounted for on an accruals basis.

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.

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

Provisions and contingencies

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. Provisions are discounted using a nominal discount rate of 3.0% (2017 2.5%).

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).

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 consolidated financial statements but are disclosed unless the possibility of an outflow of economic resources is considered remote.

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 future prices, depending on the expected timing of the activity, and discounted using the nominal discount rate. The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately 18 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 where that asset is generating or is expected to generate future economic benefits.

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 future prices and discounted using a nominal discount rate. The weighted-average period over which these costs are generally expected to be incurred is estimated to be approximately six years.

Significant judgements and estimates: 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 are political, environmental, safety and public expectations. The timing and amounts of future cash flows are subject to significant uncertainty and estimation is required in determining the amounts of provisions to be recognized. Any changes in the expected future costs are reflected in both the provision and the asset.

If oil and natural gas production facilities and pipelines are sold to third parties, judgement is required to assess whether the new owner will be unable to meet their decommissioning obligations, whether BP would then be responsible for decommissioning, and if so the extent of that responsibility.

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 current estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

The timing and amount of future expenditures relating to decommissioning and environmental liabilities are reviewed annually, together with the interest rate used in discounting the cash flows. The interest rate used to determine the balance sheet obligations at the end of 2018 was a nominal rate of 3.0% (2017 a real rate of 0.5% and a nominal rate of 2.5%), which was based on long-dated US government bonds.

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

Further information about the group's provisions is provided in Note 21. Changes in assumptions in relation to the group's provisions could result in a material change in their carrying amounts within the next financial year. A 0.5% change in the nominal discount rate could have an impact of approximately $1.3 billion on the value of the group's provisions, excluding those relating to the Gulf of Mexico oil spill. The impact on the group income statement would not be significant as the majority of the group's provisions relate to decommissioning costs.

As described in Note 33, the group is subject to claims and actions for which no provisions have been recognized. 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.

Change in significant estimate- decommissioning provision

Decommissioning provision cost estimates are reviewed regularly and such a review was undertaken in the second quarter of 2018. The timing and amount of estimated future expenditures were re-assessed and discounted to determine the present value. From 30 June 2018 the present value of the decommissioning provision is determined by discounting the estimated cash flows expressed in expected future prices, i.e. taking account of expected inflation, at a nominal discount rate of 2.5% as at 30 June 2018. Prior to 30 June 2018, the group estimated future cash flows in real terms i.e. at current prices and discounted them using a real discount rate of 0.5% as at 31 December 2017.

The impact of the review was a reduction in the provision of $1.5 billion as at 30 June 2018, with a similar reduction in the carrying amount of property, plant and equipment. There was no significant impact on the income statement for the first half of 2018. The impact on the income statement for the second half of 2018 was a decrease in depreciation, depletion and amortization of approximately $80 million and an increase in finance costs of approximately $80 million.

The nominal discount rate applied to provisions was revised at 31 December 2018 to 3.0%. The impact of this increase was a further $1.3-billion reduction in the decommissioning provision, with a similar reduction in the carrying amount of property, plant and equipment.

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 of the equity instruments on the date on which they 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.

For other equity-settled share-based payment transactions, the goods or services received and the corresponding increase in equity are measured at the fair value of the goods or services received unless their fair value cannot be reliably estimated. If the fair value of the goods and services received cannot be reliably estimated, the transaction is measured by reference to the fair value of the equity instruments granted.

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 on 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, either by way of a refund from the plan or reductions in future contributions to the plan.

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

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

Significant estimate: pensions and other post-retirement benefits

Accounting for defined benefit pensions and other post-retirement benefits involves making significant estimates when measuring the group's pension plan surpluses and deficits. These estimates require assumptions to be made about many uncertainties.

Pensions 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 that are the most significant to the amounts reported are the discount rate, inflation rate, salary growth and mortality levels. Assumptions about these variables are based on the environment in each country. The assumptions used vary from year to year, with resultant effects on future net income and net assets. Changes to some of these assumptions, in particular the discount rate and inflation rate, could result in material changes to the carrying amounts of the group's pension and other post-retirement benefit obligations within the next financial year, in particular for the UK, US and Eurozone plans. Any differences between these assumptions and the actual outcome will also affect future net income and net assets.

The values ascribed to these assumptions and a sensitivity analysis of the impact of changes in the assumptions on the benefit expense and obligation used are provided in Note 24.

Income taxes

Income tax expense represents the sum of current tax and deferred tax.

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 or increased to the extent that it is 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.

Where tax treatments are uncertain, if it is considered probable that a taxation authority will accept the group's proposed tax treatment, income taxes are recognized consistent with the group's income tax filings. If it is not considered probable, the uncertainty is reflected using either the most likely amount or an expected value, depending on which method better predicts the resolution of the uncertainty.

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 whether provisions for income taxes are required and, if so, estimation is required of the amounts that could be payable.

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 and estimates are required to be made of the amount of future taxable profits that will be available.

Management do not assess there to be a significant risk of a material change to the group’s tax provisioning or recognition of deferred tax assets within the next financial year, however the tax position remains inherently uncertain and therefore subject to change. 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 9 and Note 33.

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

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 in accordance with the applicable accounting policy such as Provisions and contingencies. No new significant judgements were made in 2018 in this regard.

Customs duties and sales taxes

Customs duties and sales taxes that are passed on or charged 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.

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 consolidated financial statements as treasury shares. Consideration, if any, received for the sale of such shares is also recognized in equity. 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 and other income

Revenue from contracts with customers is recognized when or as the group satisfies a performance obligation by transferring control of a promised good or service to a customer. The transfer of control of oil, natural gas, natural gas liquids, LNG, petroleum and chemical products, and other items usually coincides with title passing to the customer and the customer taking physical possession. The group principally satisfies its performance obligations at a point in time; the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

When, or as, a performance obligation is satisfied, the group recognizes as revenue the amount of the transaction price that is allocated to that performance obligation. The transaction price is the amount of consideration to which the group expects to be entitled. The transaction price is allocated to the performance obligations in the contract based on standalone selling prices of the goods or services promised.

Contracts for the sale of commodities are typically priced by reference to quoted prices. Revenue from term commodity contracts is recognized based on the contractual pricing provisions for each delivery. Certain of these contracts have pricing terms based on prices at a point in time after delivery has been made. Revenue from such contracts is initially recognized based on relevant prices at the time of delivery and subsequently adjusted as appropriate.

Physical exchanges with counterparties in the same line of business in order to facilitate sales to customers are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange.

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.

Where forward sale and purchase contracts for oil, natural gas or power have been determined to be for short-term trading purposes, the associated sales and purchases are reported net within sales and other operating revenues whether or not physical delivery has occurred.

Interest income is recognized as the interest accrues (using the effective interest rate, that is, the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset).

Dividend income from investments is recognized when the shareholders' right to receive the payment is established.

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.

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

Impact of new International Financial Reporting Standards

BP adopted two new accounting standards issued by the IASB with effect from 1 January 2018, IFRS 9 'Financial instruments' and IFRS 15 'Revenue from contracts with customers'. There are no other new or amended standards or interpretations adopted during the year that have a significant impact on the consolidated financial statements.

IFRS 9 'Financial Instruments'

IFRS 9 'Financial Instruments' was issued in July 2014 and replaced IAS 39 'Financial Instruments: Recognition and Measurement.' BP adopted IFRS 9 and the related consequential amendments to other IFRSs in the financial reporting period commencing 1 January 2018. The group has applied the new standard in accordance with the transition provisions of IFRS 9. Comparatives have not been restated and adjustments on transition have been reported in opening retained earnings at 1 January 2018.

The group's revised accounting policies in relation to financial instruments are provided above.

The overall impact on transition to IFRS 9, including the impact upon the group's share of equity-accounted entities, was a reduction of $180 million in net assets, net of tax. This adjustment mainly related to an increase in the loss allowance for financial assets in the scope of IFRS 9's impairment requirements. As comparatives have not been restated the closing balance at 31 December 2017 for certain line items in the balance sheet differ from the opening balance at 1 January 2018 (as summarized below). Cash and cash equivalents at the beginning of 2018 in the Group cash flow statement are the 1 January 2018 amounts included in the table below.

$ million

	31 December 2017	1 January 2018	Adjustment on adoption of IFRS 9
Non-current			
Investments in equity-accounted entities	24,985	24,903	(82)
Loans, trade and other receivables	2,080	2,069	(11)
Deferred tax liabilities	(7,982)	(7,946)	36
Current			
Loans, trade and other receivables	25,039	24,927	(112)
Cash and cash equivalents	25,586	25,575	(11)
Net assets	100,404	100,224	(180)
Reserves			
Available-for-sale investments	17	—	(17)
Costs of hedging	—	(37)	(37)
Profit and loss account	75,226	75,100	(126)
	75,243	75,063	(180)

Classification and measurement

IFRS 9 provides a single classification and measurement approach for financial assets that reflects the business model in which they are managed and their cash flow characteristics. For financial liabilities the existing classification and measurement requirements of IAS 39 are largely retained.

The table below illustrates the classification and carrying amounts of financial assets under IFRS 9 and IAS 39 at the date of initial application, 1 January 2018. There were no differences in classification or carrying amounts for financial liabilities and no differences in the measurement of liabilities for financial guarantee contracts.

$ million

At 1 January 2018	Classification under IAS 39	Classification under IFRS 9	Carrying amount under IAS 39	Measurement category adjustment on transition	Measurement attribute adjustment on transition	Carrying amount under IFRS 9
Financial assets						
Other investments – equity shares	Available-for-sale financial assets	Fair value through profit or loss	433	—	—	433
– other	Available-for-sale financial assets	Fair value through profit or loss	275	—	—	275
– other	At fair value through profit or loss	Fair value through profit or loss	662	—	—	662
Loans	Loans and receivables	Amortized cost	836	(100)	—	736
Loans	Loans and receivables	Fair value through profit or loss	—	100	(8)	92
Trade and other receivables	Loans and receivables	Amortized cost	24,361	—	(115)	24,246
Derivative financial instruments	At fair value through profit or loss	Fair value through profit or loss	6,454	—	—	6,454
Derivative financial instruments	Derivative hedging instruments	Derivative hedging instruments	688	—	—	688
Cash and cash equivalents	Loans and receivables	Amortized cost	21,916	—	(11)	21,905
Cash and cash equivalents	Available-for-sale financial assets	Amortized cost	2,270	(2,058)	—	212
Cash and cash equivalents	Available-for-sale financial assets	Fair value through profit or loss	—	2,058	—	2,058
Cash and cash equivalents	Held-to-maturity investments	Amortized cost	1,400	—	—	1,400
			59,295	—	(134)	59,161

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

Other investments existing on transition that were classified as available-for-sale financial assets under IAS 39 are classified as mandatorily measured at fair value through profit or loss (FVTPL) under IFRS 9. The contractual terms of these assets do not give rise to cash flows that are solely payments of principal and interest. Fair value gains and losses will be recognized in profit or loss rather than in other comprehensive income as was the case under IAS 39. An adjustment to the 2018 opening balance sheet was made to transfer $17 million of fair value gains net of related tax from the available-for-sale investments reserve to the profit and loss account reserve.

Certain loans that were classified as loans and receivables under IAS 39 have been classified as mandatorily measured at FVTPL under IFRS 9 as a result of the business model in which they are held. The adjustment of $8m to the carrying amount of these assets on transition reflects the difference between amortized cost measurement under IAS 39 and fair value measurement under IFRS 9.

Cash and cash equivalents that were classified as available-for-sale and held-to-maturity financial assets under IAS 39 have been classified as either measured at amortized cost or measured at FVTPL under IFRS 9. Cash and cash equivalents measured at FVTPL comprise money market funds that do not give rise to cash flows that are solely payments of principal and interest. For cash and cash equivalents that have been reclassified to measured at amortized cost, the carrying amount of those assets at the end of the reporting period approximate their fair value. The fair value gain or loss that would have been recognized in other comprehensive income in the reporting period if those financial assets had not been reclassified to amortized cost is immaterial.

Adjustments to the carrying amount of financial assets classified as measured at amortized cost under IFRS 9 relate entirely to the additional loss allowance required by the new standard's expected credit loss model.

There were no financial assets or financial liabilities which the group had previously designated as at FVTPL under IAS 39 that were required to be reclassified, or which the group has elected to reclassify upon the application of IFRS 9. The group did not elect to designate at FVTPL any financial assets or financial liabilities at the date of initial application of IFRS 9.

Under IFRS 9 the group has elected to apply hedge accounting prospectively to certain of its commodity price risk management activities for which hedge accounting was not possible under IAS 39. Certain derivatives that were previously classified as at FVTPL have therefore been reclassified to derivative hedging instruments at 1 January 2018. As the hedging instruments are exchange traded derivatives, the value transferred on transition was nil.

Impairment

The financial asset impairment requirements of IFRS 9 introduce a forward-looking expected credit loss model that results in earlier recognition of credit losses than the incurred loss model of IAS 39. The adjustment to the 2018 opening balance sheet relating to expected credit loss reduced both the carrying amounts of financial assets and the profit and loss account reserve.

The table below reconciles the ending impairment allowances in accordance with IAS 39 and the provisions in accordance with IAS 37 to the opening loss allowances determined in accordance with IFRS 9.

						$ million
At 1 January 2018	Classification under IAS 39	Classification under IFRS 9	IAS 39 loss allowance	Measurement category effect on transition	Measurement attribute adjustment on transition	IFRS 9 loss allowance
Financial assets						
Other investments – equity shares	Available-for-sale financial assets	Fair value through profit or loss	91	(91)	—	—
Trade and other receivables	Loans and receivables	Amortized cost	335	—	115	450
Cash and cash equivalents	Loans and receivables	Amortized cost	—	—	11	11
Total loss allowance on financial assets			426	(91)	126	461
Loans that form part of the net investment in equity-accounted entities			37	—	6	43
Total loss allowance			463	(91)	132	504

Impairment allowances on available-for-sale assets represent amounts provided against investments in equity instruments that were held at cost under IAS 39. Under IFRS 9 these assets are classified as measured at fair value through profit or loss and therefore no loss allowance exists on these assets under IFRS 9.

The increase in the loss allowances for financial assets classified as measured at amortized cost under IFRS 9 and loans that form part of the net investment in equity-accounted entities represent the additional loss allowance required by the new standard's expected credit loss model.

Hedge accounting

Under IFRS 9 all existing hedging relationships qualified as continuing hedging relationships and the group has applied hedge accounting prospectively to certain of its commodity price risk management activities for which hedge accounting was not possible under IAS 39.

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

IFRS 9 also introduces a new way of treating fair value movements on the time value and foreign currency basis spreads of certain hedging instruments. Whereas under IAS 39 these movements were recognized in profit or loss, the group is either required, or has elected to initially recognize these movements within equity to the extent that they relate to the hedged item. An adjustment to the 2018 opening balance sheet was made to transfer $37 million of losses net of related tax from the profit and loss account reserve to the costs of hedging reserve for relevant hedging instruments existing on transition.

Under IAS 39 the effective portion of the gain or loss on a cash flow hedging instrument is reported in other comprehensive income and is reclassified to the balance sheet as part of the initial carrying amount of the corresponding non-financial asset or liability. Under IFRS 9 the effective portion of the gain or loss continues to be reported in the statement of other comprehensive income but the transfer to the balance sheet is shown in the statement of changes in equity.

IFRS 15 'Revenue from Contracts with Customers'

IFRS 15 'Revenue from Contracts with Customers' was issued in May 2014 and replaced IAS 18 'Revenue' and certain other standards and interpretations. IFRS 15 provides a single model for accounting for revenue arising from contracts with customers, focusing on the identification and satisfaction of performance obligations. BP adopted IFRS 15 from 1 January 2018 and applied the 'modified retrospective' transition approach to implementation.

The group's revised accounting policy in relation to revenue is provided above. A disaggregation of revenue from contracts with customers is provided in note 5.

The group identified certain minor changes in accounting relating to its revenue from contracts with customers but the new standard had no material effect on the group's net assets as at 1 January 2018 and so no transition adjustment is presented.

The most significant change identified is the accounting for revenues relating to oil and natural gas properties in which the group has an interest with joint operation partners. From 1 January 2018, BP ceased using the entitlement method of accounting under which revenue was recognized in relation to the group's entitlement to the production from oil and gas properties based on its working interest, irrespective of whether the production was taken and sold to customers. In its 2018 consolidated financial statements the group has recognized revenue when sales are made to customers; production costs have been accrued or deferred to reflect differences between volumes taken and sold to customers and the group's ownership interest in total production volumes. Compared to the group's previous accounting policy this may result in timing differences in respect of revenues and profits recognized in each period, but there will be no change in the total revenues and profits over the duration of the joint operation. The impact on the consolidated financial statements for the year ended 31 December 2018 was not material.

In addition, BP has made determinations about presentation and disclosure relating to its revenue from contracts with customers as follows:

Derivative contracts resulting in physical delivery to a customer

Certain contracts entered into by the group that result in physical delivery to a counterparty of products such as crude oil, natural gas and refined products are required by IFRS to be accounted for as financial instruments. These contracts are within the scope of IFRS 9 rather than IFRS 15. The group's counterparties in these transactions, however, may meet the IFRS 15 definition of a customer. Revenue recognized relating to such contracts when physical delivery occurs is, therefore, presented together with revenue from contracts with customers in the group's consolidated financial statements. Changes in the fair value of derivative assets and liabilities prior to physical delivery are excluded from revenue from contracts with customers and are presented as other operating revenues. Additionally, where forward sales and purchase contracts for oil, natural gas or power have been determined to be for short-term trading purposes, the associated sales and purchases continue to be reported net within other operating revenues consistent with the group's practice prior to implementation of IFRS 15.

Contracts with post-delivery pricing terms

Contracts entered into by the group for the sale of oil, natural gas (including LNG), NGLs and refined products are typically priced by reference to quoted prices. In line with market practice, certain of these contracts are based on average prices over a period that is partially or entirely after delivery. Revenue relating to such contracts is recognized initially based on relevant prices at the time of delivery and subsequently adjusted as prices are finalized, consistent with the group's practice prior to implementation of IFRS 15. Whilst these post-delivery adjustments are changes in the value of receivables within the scope of IFRS 9, not IFRS 15, the distinction between revenue recognized at the time of delivery and revenue recognized as a result of post-delivery changes in quoted commodity prices relating to the same transaction is not considered to be significant. All revenue from these contracts, both that recognized at the time of delivery and that from post-delivery price adjustments, is disclosed as revenue from contracts with customers.

Disclosure of the amount of the transaction price allocated to unsatisfied performance obligations

The disclosures required by IFRS 15 include the amount of the contract transaction price allocated to performance obligations that are unsatisfied at the balance sheet date. Many of BP's commodity sales are made under term contracts in which sales are made based on quoted prices at or near the time of delivery, meaning the consideration for future deliveries is entirely variable. In these arrangements, each delivery is considered to be a separate performance obligation and the transaction price is the amount of revenue expected to be earned from all sales that are contracted to be made in future periods, which can be up to 20 years from the balance sheet date.

BP does not consider the disclosure of the amount of the transaction price allocated to contracted future deliveries of commodities within the scope of IFRS 15 to be relevant information. This disclosure has not, therefore, been provided in these consolidated financial statements. The consideration in many such contracts is entirely variable so would be subject to the requirement of IFRS 15 relating to constraining estimates of variable consideration. Applying the constraint for the purposes of this disclosure requirement would provide an indication only of contracted revenues based on estimated future minimum market prices. Such commodities are regularly sold in liquid markets on a spot basis, using similar pricing bases to sales made under term contracts, meaning that disclosure of contracted sales would have little predictive value. Furthermore, as described above, a significant proportion of the group's commodity sales contracts are within the scope of IFRS 9, not IFRS 15. Derivative assets or liabilities representing the difference between contracted price and forward price are recognized on the group balance sheet for these contracts.

Contract assets and liabilities

The group does not have material contract asset or contract liability balances and so these amounts are included within amounts presented for trade receivables and other payables.

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

Not yet adopted

The IASB has issued IFRS 16 'Leases' which will become effective from financial reporting periods beginning on or after 1 January 2019 and has been adopted by the EU. The group has not adopted IFRS 16 in these consolidated financial statements and will adopt it from 1 January 2019. 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.

IFRS 16 'Leases'

IFRS 16 'Leases' provides a new model for lessee accounting in which the majority of leases will be accounted for by the recognition on the balance sheet of a right-of-use asset and a lease liability. The subsequent amortization of the right-of-use asset and the interest expense related to the lease liability will be recognized in profit or loss over the lease term. IFRS 16 replaces IAS 17 'Leases' and IFRIC 4 'Determining whether an arrangement contains a lease' and will be effective for financial reporting periods beginning on or after 1 January 2019.

BP will adopt IFRS 16 in the financial reporting period commencing 1 January 2019 and has elected to apply the modified retrospective transition approach in which the cumulative effect of initial application is recognized in opening retained earnings at the date of initial application with no restatement of comparative periods' financial information.

IFRS 16 introduces a revised definition of a lease. As permitted by the standard, BP has elected not to reassess the existing population of leases under the new definition and will only apply the new definition for the assessment of contracts entered into after the transition date. On transition the standard permits, on a lease-by-lease basis, the right-of-use asset to be measured either at an amount equal to the lease liability (as adjusted for prepaid or accrued lease payments), or on an historical basis as if the standard had always applied. BP has elected to use the historical asset measurement for its more material leases and to use the asset equals liability approach for the remainder of the population. In addition, BP has also elected the option to adjust the carrying amounts of the right-of-use assets as at 1 January 2019 for onerous lease provisions that had been recognized on the group balance sheet as at 31 December 2018, rather than the alternative of performing impairment tests on transition.

The group's evaluation of the effect of adoption of the standard is substantially complete and a material effect on the group's balance sheet is expected, as set out further below. The presentation and timing of recognition of charges in the income statement will also change as the operating lease expense currently reported under IAS 17, typically on a straight-line basis, will be replaced by depreciation of the right-of-use asset and interest on the lease liability. In the cash flow statement operating lease payments are currently presented within cash flows from operating activities but under IFRS 16 payments will be presented as financing cash flows, representing repayments of debt, and as operating cash flows, representing payments of interest. Variable lease payments that do not depend on an index or rate are not included in the lease liability and will continue to be presented as operating cash flows.

Information on the group's leases classified as operating leases under IAS 17, which are not recognized on the balance sheet as at 31 December 2018, is presented in Note 28. The following table provides a reconciliation of the operating lease commitments disclosed in Note 28 to the total lease liability expected to be recognized on the group balance sheet in accordance with IFRS 16 as at 1 January 2019, with explanations below.

	$ million
Operating lease commitments at 31 December 2018	11,979
Leases not yet commenced	(1,372)
Leases below materiality threshold	(86)
Short-term leases	(91)
Effect of discounting	(1,512)
Impact on leases in joint operations	836
Variable lease payments	(58)
Redetermination of lease term	(252)
Other	(22)
Total additional lease liabilities expected to be recognized on adoption of IFRS 16	9,422
Finance lease obligations at 31 December 2018	667
Adjustment for finance leases in joint operations	(189)
Total expected lease liabilities at 1 January 2019	9,900

Leases not yet commenced: The operating lease commitments disclosed in Note 28 include amounts relating to leases entered into by the group that had not yet commenced as at 31 December 2018. In accordance with IFRS 16 assets and liabilities will not be recognized on the group balance sheet in relation to these leases until the dates of commencement of the leases. Such commitments will continue to be disclosed in future under IFRS 16.

Short-term leases and leases below materiality threshold: As part of the transition to IFRS 16, BP has elected not to recognize assets and liabilities relating to short-term leases i.e. leases with a term of less than 12 months and has also applied a materiality threshold for the recognition of assets and liabilities related to leases. The disclosed operating lease commitments as at 31 December 2018 in Note 28 includes amounts related to such leases.

Effect of discounting: The amount of the lease liability recognized in accordance with IFRS 16 will be on a discounted basis whereas the operating lease commitments information in Note 28 is presented on an undiscounted basis. The discount rates used on transition are incremental borrowing rates as appropriate for each lease based on factors such as the lessee legal entity, lease term and currency. The weighted average discount rate to be used on transition is expected to be around 3.5%, with a weighted average remaining lease term of around 9 years. For new leases commencing after 1 January 2019 the discount rate used will be the interest rate implicit in the lease, if this is readily determinable, or the incremental borrowing rate if the implicit rate cannot be readily determined.

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

Impact on leases in joint operations: The operating lease commitments for leases within joint operations are included on the basis of BP's net working interest for the information provided in Note 28, irrespective of whether BP is the operator and whether the lease has been co-signed by the joint operators or not. However, for transition to IFRS 16, the facts and circumstances of each lease in a joint operation have been assessed to determine the group's rights and obligations and to recognize assets and liabilities on the group balance sheet accordingly. This relates mainly to leases of drilling rigs within joint operations in the Upstream segment. Where all parties to a joint operation jointly have the right to control the use of the identified asset and all parties have a legal obligation to make lease payments to the lessor, the group's share of the right-of-use asset and its share of the lease liability will be recognized on the group balance sheet. This may arise in cases where the lease is signed by all parties to the joint operation. However, in cases where BP is the only party with the legal obligation to make lease payments to the lessor, the full lease liability will be recognized on the group balance sheet. This may be the case if for example BP, as operator of the joint operation, is the sole signatory to the lease. If, however, the underlying asset is jointly controlled by all parties to the joint operation BP will recognize its net share of the right-of-use asset on the group balance sheet along with a receivable representing the amounts to be recovered from the other parties. If BP is not legally obliged to make lease payments to the lessor but jointly controls the asset, the net share of the right-of-use asset will be recognized on the group balance sheet along with a payable representing amounts to be paid to the other parties.

Variable lease payments: Where there are lease payments that vary depending on an index or rate, the measurement of the operating lease commitments in Note 28 is based on the variable factor as at inception of the lease and is not updated to reflect subsequent changes in the variable factor. Such subsequent changes in the lease payments are currently treated as contingent rentals and charged to profit or loss as and when paid. Under IFRS 16 the lease liability will be adjusted whenever the lease payments are changed in response to changes in the variable factor, and for transition the liability is measured on the basis of the prevailing variable factor on 1 January 2019.

Redetermination of lease term: Under the transition provisions of IFRS 16, the remaining terms of certain leases have been redetermined with the benefit of hindsight, on the basis that BP is now reasonably certain to exercise its option to terminate those leases before the full term.

Under IAS 17 finance leases are recognized on the group balance sheet and will continue to be recognized in accordance with IFRS 16. The amounts recognized on the group balance sheet as at 1 January 2019 in relation to the right-of-use assets and liabilities for existing finance leases within joint operations will be on a net or gross basis as appropriate as described above.

In addition to the lease liability, which will be presented within finance debt, other line items on the group balance sheet expected to be adjusted on transition to IFRS 16 include property, plant and equipment, prepayments, receivables, accruals, payables, provisions and deferred tax balances, as set out below.

			$ million
	31 December 2018	1 January 2019	Adjustment on adoption of IFRS 16
Non-current assets			
Property, plant and equipment	135,261	143,950	8,689
Trade and other receivables	1,834	2,159	325
Prepayments	1,179	849	(330)
Deferred tax assets	3,706	3,736	30
Current assets			
Trade and other receivables	24,478	24,673	195
Prepayments	963	872	(91)
Current liabilities			
Trade and other payables	46,265	46,209	(56)
Accruals	4,626	4,578	(48)
Finance debt and leases	9,373	11,525	2,152
Provisions	2,564	2,547	(17)
Non-current liabilities			
Other payables	13,830	14,013	183
Accruals	575	548	(27)
Finance debt and leases	56,426	63,507	7,081
Deferred tax liabilities	9,812	9,767	(45)
Provisions	17,732	17,657	(75)
Net assets	101,548	101,218	(330)
Equity			
BP shareholders' equity	99,444	99,115	(329)
Non-controlling interests	2,104	2,103	(1)
	101,548	101,218	(330)

The total expected adjustments to the group's lease liabilities at 1 January 2019 may be reconciled as follows:

	$ million
Total additional lease liabilities expected to be recognized on adoption of IFRS 16	9,422
Less: adjustment for finance leases in joint operations	(189)
Total expected adjustment to lease liabilities	9,233
Of which – current	2,152
– non-current	7,081

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.

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
	2018	2017	2016
Income statement			
Production and manufacturing expenses	**714**	2,687	6,640
Profit (loss) before interest and taxation	**(714)**	(2,687)	(6,640)
Finance costs	**479**	493	494
Profit (loss) before taxation	**(1,193)**	(3,180)	(7,134)
Less: Taxation	**174**	(2,222)	3,105
Profit (loss) for the period	**(1,019)**	(5,402)	(4,029)
Balance sheet			
Current assets			
Trade and other receivables	**214**	252	
Current liabilities			
Trade and other payables	**(2,279)**	(2,089)	
Provisions	**(333)**	(1,439)	
Net current assets (liabilities)	**(2,398)**	(3,276)	
Non-current assets			
Deferred tax	**1,563**	2,067	
Non-current liabilities			
Other payables	**(11,922)**	(12,253)	
Provisions	**(12)**	(1,141)	
Deferred tax	**3,999**	3,634	
Net non-current assets (liabilities)	**(6,372)**	(7,693)	
Net assets (liabilities)	**(8,770)**	(10,969)	
Cash flow statement			
Profit (loss) before taxation	**(1,193)**	(3,180)	(7,134)
Net charge for interest and other finance expense, less net interest paid	**479**	493	494
Net charge for provisions, less payments	**240**	2,542	4,353
(Increase) decrease in other current and non-current assets	**(485)**	(1,738)	(3,210)
Increase (decrease) in other current and non-current liabilities	**(2,572)**	(3,453)	(1,608)
Pre-tax cash flows	**(3,531)**	(5,336)	(7,105)

Income statement

The group income statement for 2018 includes a pre-tax charge of $1,193 million (2017 pre-tax charge of $3,180 million, 2016 pre-tax charge of $7,134 million) in relation to the Gulf of Mexico oil spill. The charge within production and manufacturing expenses in 2018 of $714 million (2017 $2,687 million, 2016 $6,640 million) relates mainly to business economic loss (BEL) and other claims associated with the Deepwater Horizon Court Supervised Settlement Program (DHCSSP). Finance costs of $479 million (2017 $493 million, 2016 $494 million) reflect the unwinding of the discount on payables and, for 2016, 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 2012 agreement with the US government to resolve all federal criminal claims arising from the incident, amounts charged for the 2016 consent decree and settlement agreement with the United States and the five Gulf coast states including amounts payable for natural resource damages, state claims and Clean Water Act penalties, operating costs, amounts charged upon initial recognition of the trust obligation, other litigation, claims, environmental and legal costs and estimated obligations for future costs, net of settlements agreed with the co-owners of the Macondo well and other third parties.

The cumulative pre-tax income statement charge since the incident amounts to $67.0 billion and is analysed in the table below.

				$ million
	2018	2017	2016	Cumulative since the incident
Environmental costs	**—**	—	—	8,526
Spill response costs	**—**	—	—	14,304
Litigation and claims costs	**629**	2,647	6,596	42,410
Clean Water Act penalties	**—**	—	—	4,061
Other costs	**85**	40	44	1,394
Settlements credited to the income statement	**—**	—	—	(5,681)
(Profit) loss before interest and taxation	**714**	2,687	6,640	65,014
Finance costs	**479**	493	494	1,944
(Profit) loss before taxation	**1,193**	3,180	7,134	66,958

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

Provisions and contingent liabilities

Provisions

Movements during the year in the remaining provision, which relates to litigation and claims, are presented in the table below.

	$ million
	2018
	Litigation and claims
At 1 January	**2,580**
Increase in provision	**629**
Reclassified to other payables	**(2,045)**
Utilization	**(819)**
At 31 December	**345**
Of which – current	**333**
– non-current	**12**

Litigation and claims – PSC settlement

The Economic and Property Damages Settlement Agreement (EPD Settlement Agreement) with the Plaintiffs' Steering Committee (PSC) provides for a court-supervised settlement programme, the DHCSSP, which commenced operation on 4 June 2012. A separate claims administrator was 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 296.

The litigation and claims provision reflects the latest estimate for the remaining costs associated with the PSC settlement. These costs relate predominantly to BEL claims and associated administration costs. The amounts ultimately payable may differ from the amount provided and the timing of payments is uncertain.

The DHCSSP's determination of BEL claims was substantially completed by the end of 2017 and remaining claims continued to be processed throughout 2018 with only a very small number of claims remaining to be determined by the end of 2018. However certain BEL claims determined by the DHCSSP have been and continue to be appealed by BP and/or the claimants.

During 2018 settlement agreements were reached with claimants for a significant proportion of the provision existing at the beginning of the year. Amounts payable under these settlement agreements have been reclassified from provisions to other payables. The remaining amount provided for includes the latest estimate of the amounts that are expected ultimately to be paid to resolve outstanding BEL claims. Claims under appeal will ultimately only be resolved once the full judicial appeals process has been concluded, including appeals to the Federal District Court and Fifth Circuit, as may be the case, or when settlements are reached with individual claimants. Depending upon the ultimate resolution of these claims, the amounts payable may differ from those currently provided.

Payments to resolve outstanding claims under the PSC settlement are expected to be made over a number of years. The timing of payments, however, is uncertain, and, in particular, will be impacted by how long it takes to resolve claims that have been appealed and may be appealed in the future.

Contingent liabilities

For information on legal proceedings relating to the Deepwater Horizon oil spill, see Legal proceedings on pages 296-298. Any further outstanding Deepwater Horizon related claims are not expected to have a material impact on the group's financial performance.

Other payables

Other payables include amounts payable under the 2016 consent decree and settlement agreement with the United States and five Gulf coast states, including amounts payable for natural resource damages, state claims and Clean Water Act penalties. On a discounted basis the amounts included in other payables for these elements of the agreements are $5,485 million payable over 14 years, $2,897 million payable over 15 years and $4,010 million payable over 14 years respectively at 31 December 2018. For full details of these agreements, see *BP Annual Report and Form 20-F 2015*.

In addition, other payables at 31 December 2018 also includes amounts payable for settled economic loss and property damage claims which are payable over a period of up to nine years.

Cash flow statement

The impact on net cash provided by operating activities on a pre-tax basis amounted to an outflow of $3,531 million (2017 outflow of $5,336 million, 2016 outflow of $7,105 million). On a post-tax basis, the amounts were an outflow of $3,218 million (2017 outflow of $5,167 million and 2016 outflow of $6,892 million).

Cash outflows in 2018, 2017 and 2016 include payments made under the 2012 agreement with the US government to resolve all federal criminal claims arising from the incident and the 2016 consent decree and settlement agreement with the United States and the five Gulf coast states.

3. Business combinations and other significant transactions

Business combinations

BP undertook a number of business combinations in 2018. For the full year, total consideration paid in cash amounted to $7,100 million, offset by cash acquired of $114 million.

On 31 October 2018, BP acquired from BHP Billiton Petroleum (North America) Inc. 100% of the issued share capital of Petrohawk Energy Corporation, a wholly owned subsidiary of BHP that holds a portfolio of unconventional onshore US oil and gas assets.

The acquisition brings BP extensive oil and gas production and resources in the liquids-rich regions of the Permian and Eagle Ford basins in Texas and in the Haynesville gas basin in Texas and Louisiana.

The total consideration for the transaction, after customary closing adjustments and the effect of discounting deferred payments, is $10,302 million, which will all be paid in cash. As at 31 December 2018, $6,788 million of the consideration had been paid. The remaining discounted amount of $3,514 million is included within other payables on the group balance sheet and will be paid in four instalments, with the final instalment being paid in April 2019.

The transaction has been accounted for as a business combination using the acquisition method. The provisional fair values of the identifiable assets and liabilities acquired, as at the date of acquisition, are shown in the table below. No goodwill has been recognized on the acquisition.

	$ million
	2018
Assets	
Property, plant and equipment	**10,845**
Intangible assets	**21**
Inventories	**27**
Trade and other receivables	**493**
Cash	**104**
Liabilities	
Trade and other payables	**(659)**
Provisions	**(323)**
Non-controlling interest	**(206)**
Total consideration	**10,302**

The acquisition-date fair values of the assets and liabilities acquired are provisional. As we gain further understanding of the acquired properties and development options, these fair values may be adjusted.

An analysis of the cash flows relating to the acquisition included within the cash flow statement for 2018 is provided below.

	$ million
	2018
Transaction costs of the acquisition (included in cash flows from operating activities)	**62**
Interest on deferred payments (included in cash flows from operating activities)	**21**
Cash consideration paid, net of cash acquired (included in cash flows from investing activities)	**6,684**
Total net cash outflow for the acquisition	**6,767**

From the date of acquisition to 31 December 2018, the acquired activities generated revenues of $472 million and profit before tax of $49 million. If the business combination had taken place on 1 January 2018, it is estimated that the acquired activities would have generated revenues of $2,798 million and profit before tax of $431 million.

In addition to the BHP transaction described above, BP undertook a number of other individually insignificant business combinations in 2018.

Other significant transactions

On 18 December 2018, BP purchased an additional 16.5% interest in the Clair field in the North Sea, as part of the agreements with ConocoPhillips in which ConocoPhillips simultaneously purchased BP's entire 39.2% interest in the Greater Kuparuk Area on the North Slope of Alaska. The purchase gives BP a 45.1% interest in Clair in total. Gross payments made and received of $1,739 million and $1,490 million are included in Capital expenditure and Proceeds from disposals of businesses, net of cash acquired, respectively, in the group cash flow statement. Goodwill of $804 million, resulting from the recognition of a deferred tax liability as part of the transaction accounting, has been recognized on the purchase of the interest in the Clair field.

4. Disposals and impairment

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

			$ million
	2018	2017	2016
Gains on sale of businesses and fixed assets			
Upstream	**437**	526	557
Downstream	**15**	674	561
Other businesses and corporate	**4**	10	14
	456	1,210	1,132

			$ million
	2018	2017	2016
Losses on sale of businesses and fixed assets			
Upstream	**707**	127	169
Downstream	**59**	88	89
Other businesses and corporate	**11**	—	3
	777	215	261
Impairment losses			
Upstream	**400**	1,138	1,022
Downstream	**12**	69	84
Other businesses and corporate	**254**	32	11
	666	1,239	1,117
Impairment reversals			
Upstream	**(580)**	(176)	(3,025)
Downstream	**(2)**	(62)	(17)
Other businesses and corporate	**(1)**	—	—
	(583)	(238)	(3,042)
Impairment and losses on sale of businesses and fixed assets	**860**	1,216	(1,664)

Disposals

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

			$ million
	2018	2017	2016
Proceeds from disposals of fixed assets	**940**	2,936	1,372
Proceeds from disposals of businesses, net of cash disposed	**1,911**	478	1,259
	2,851	3,414	2,631
By business			
Upstream	**2,145**	1,183	839
Downstream	**120**	2,078	1,646
Other businesses and corporate	**586**	153	146
	2,851	3,414	2,631

At 31 December 2018, deferred consideration relating to disposals amounted to $35 million receivable within one year (2017 $259 million and 2016 $255 million) and $304 million receivable after one year (2017 $268 million and 2016 $271 million). In addition, contingent consideration receivable relating to disposals amounted to $893 million at 31 December 2018 (2017 $237 million and 2016 $131 million). These amounts of contingent consideration are reported within Other investments on the group balance sheet - see Note 18 for further information.

Upstream

In 2018, gains principally resulted from the disposal of interests in the Bruce, Keith and Rhum fields in the UK North Sea, from the disposal of certain properties in the US, and from adjustments to disposals in prior periods. Losses included $335 million resulting from the disposal of our interest in the Magnus field and associated assets in the UK North Sea, $221 million from the disposal of our interest in the Greater Kuparuk Area in the US (see Note 3 for further information), and adjustments to disposals in prior periods.

In 2017, gains principally resulted from the disposal of a portion of our interest in the Perdido offshore hub in the US, and further gains associated with disposals in the UK.

In 2016, gains principally resulted from the contribution of BP's Norwegian upstream business into Aker BP ASA and from the sale of certain properties in the UK.

Downstream

In 2017, gains principally resulted from the disposal of our interest in the SECCO joint venture and the disposal of certain midstream assets in Europe.

In 2016, gains principally resulted from the disposal of certain US and non-US midstream assets in our fuels business and the dissolution of our German refining joint operation with Rosneft.

Other businesses and corporate

In 2018 proceeds from disposals were principally in respect of life insurance policies in the US and wind farms within our US wind business.

4. Disposals and impairment – continued

Summarized financial information relating to the sale of businesses is shown in the table below. The principal transaction categorized as a business disposal in 2018 was the disposal of our interest in the Greater Kuparuk Area in the US - see Note 3 for further information. The principal transaction categorized as a business disposal in 2017 was the disposal of our interest in the Forties Pipeline System in the North Sea. The principal transactions categorized as business disposals in 2016 were the contribution of BP's Norwegian upstream business into Aker BP ASA and the dissolution of the group's German refining joint operation with Rosneft.

			$ million
	2018	2017	2016
Non-current assets	**3,274**	735	4,794
Current assets	**173**	57	1,202
Non-current liabilities	**(250)**	(173)	(2,558)
Current liabilities	**(97)**	(86)	(532)
Total carrying amount of net assets disposed	**3,100**	533	2,906
Recycling of foreign exchange on disposal	**—**	—	25
Costs on disposal[a]	**3**	3	229
	3,103	536	3,160
Gains (losses) on sale of businesses[b]	**(221)**	44	593
Total consideration	**2,882**	580	3,753
Non-cash consideration[c]	**(282)**	(216)	(2,698)
Consideration received (receivable)	**(689)**	114	204
Proceeds from the sale of businesses, net of cash disposed[d]	**1,911**	478	1,259

[a] 2016 includes amounts relating to the remeasurement to fair value of certain assets as a result of the dissolution of our German refining joint operation with Rosneft.

[b] 2016 gains on sale of businesses include deferred amounts not recognized in the income statement.

[c] 2016 non-cash consideration principally relates to the contribution of BP's Norwegian upstream business into Aker BP ASA in exchange for 30% interest in Aker BP ASA and the dissolution of the group's German refining joint operation with Rosneft.

[d] Proceeds are stated net of cash and cash equivalents disposed of $15 million (2017 $25 million and 2016 $676 million).

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. See also Note 12, Note 15 and Note 21 for further information on impairments by asset category.

Upstream

Impairment losses and reversals related primarily to producing and midstream assets.

The 2018 impairment losses of $400 million related to a number of different assets, with the most significant charges arising in Australia and the US. Impairment losses arose primarily as a result of changes to project activity, asset obsolescence and the decision to dispose of certain assets. The 2018 impairment reversals of $580 million related to a number of different assets, with the most significant reversals arising in the North Sea and Angola following a change to decommissioning cost estimates.

The 2017 impairment losses of $1,138 million related to a number of different assets, with the most significant charges arising in BPX Energy (previously known as the US Lower 48 business) and the North Sea. Impairment losses within Upstream arose primarily as a result of changes in reserves estimates and the decision to dispose of certain assets, including the Forties Pipeline System business.

The 2017 impairment reversals of $176 million related to a number of different assets, with the most significant reversals arising in the North Sea.

The 2016 impairment losses of $1,022 million related to a number of different assets, with the most significant charges arising in the North Sea. Impairment losses within Upstream arose primarily as a result of revised cost estimates and decisions to dispose of certain assets.

The 2016 impairment reversals of $3,025 million primarily related to the North Sea and Angola. The largest impairment reversals related to the Andrew area cash-generating unit (CGU) in the North Sea and the PSVM and Greater Plutonio CGUs in Angola but none of these were individually significant. In addition an impairment reversal was recorded in relation to the Block KG D6 CGU in India; and exploration costs were also written back during the period (see Note 8). The impairment reversals arose following a reduction in the discount rate applied, changes to future price assumptions, and also increased confidence in the progress of the KG D6 projects in India.

Downstream

Impairment losses totalling $12 million, $69 million, and $84 million were recognized in 2018, 2017 and 2016 respectively.

Other businesses and corporate

Impairment losses totalling $254 million, $32 million, and $11 million were recognized in 2018, 2017 and 2016 respectively. The amount for 2018 is in respect of assets within our US wind business in advance of their disposal in December 2018.

5. Segmental analysis

The group's organizational structure reflects the various activities in which BP is engaged. At 31 December 2018, 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.

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 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

$ million

2018

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
Segment revenues						
Sales and other operating revenues	**56,399**	**270,689**	**—**	**1,678**	**(30,010)**	**298,756**
Less: sales and other operating revenues between segments	**(28,565)**	**(574)**	**—**	**(871)**	**30,010**	**—**
Third party sales and other operating revenues	**27,834**	**270,115**	**—**	**807**	**—**	**298,756**
Earnings from joint ventures and associates – after interest and tax	**951**	**589**	**2,283**	**(70)**	**—**	**3,753**
Segment results						
Replacement cost profit (loss) before interest and taxation	**14,328**	**6,940**	**2,221**	**(3,521)**	**211**	**20,179**
Inventory holding gains (losses)[a]	**(6)**	**(862)**	**67**	**—**	**—**	**(801)**
Profit (loss) before interest and taxation	**14,322**	**6,078**	**2,288**	**(3,521)**	**211**	**19,378**
Finance costs						**(2,528)**
Net finance expense relating to pensions and other post-retirement benefits						**(127)**
Profit (loss) before taxation						**16,723**
Other income statement items						
Depreciation, depletion and amortization						
US	**4,211**	**900**	**—**	**59**	**—**	**5,170**
Non-US	**8,907**	**1,177**	**—**	**203**	**—**	**10,287**
Charges for provisions, net of write-back of unused provisions, including change in discount rate	**355**	**834**	**—**	**1,557**	**—**	**2,746**
Segment assets						
Investments in joint ventures and associates	**12,785**	**2,772**	**10,074**	**689**	**—**	**26,320**
Additions to non-current assets[b]	**11,533**	**2,862**	**—**	**245**	**—**	**14,640**

[a] See explanation of inventory holding gains and losses on page 156.

[b] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

$ million

2017

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
Segment revenues						
Sales and other operating revenues	45,440	219,853	—	1,469	(26,554)	240,208
Less: sales and other operating revenues between segments	(24,179)	(1,800)	—	(575)	26,554	—
Third party sales and other operating revenues	21,261	218,053	—	894	—	240,208
Earnings from joint ventures and associates – after interest and tax	930	674	922	(19)	—	2,507
Segment results						
Replacement cost profit (loss) before interest and taxation	5,221	7,221	836	(4,445)	(212)	8,621
Inventory holding gains (losses)[a]	8	758	87	—	—	853
Profit (loss) before interest and taxation	5,229	7,979	923	(4,445)	(212)	9,474
Finance costs						(2,074)
Net finance expense relating to pensions and other post-retirement benefits						(220)
Profit (loss) before taxation						7,180
Other income statement items						
Depreciation, depletion and amortization						
US	4,631	875	—	65	—	5,571
Non-US	8,637	1,141	—	235	—	10,013
Charges for provisions, net of write-back of unused provisions, including change in discount rate	220	304	—	2,902	—	3,426
Segment assets						
Investments in joint ventures and associates	12,093	2,349	10,059	484	—	24,985
Additions to non-current assets[b]	14,500	2,677	—	275	—	17,452

[a] See explanation of inventory holding gains and losses on page 156.

[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	Consolidation adjustment and eliminations	Total group
						$ million
						2016
Segment revenues						
Sales and other operating revenues	33,188	167,683	—	1,667	(19,530)	183,008
Less: sales and other operating revenues between segments	(17,581)	(1,291)	—	(658)	19,530	—
Third party sales and other operating revenues	15,607	166,392	—	1,009	—	183,008
Earnings from joint ventures and associates – after interest and tax	723	608	647	(18)	—	1,960
Segment results						
Replacement cost profit (loss) before interest and taxation	574	5,162	590	(8,157)	(196)	(2,027)
Inventory holding gains (losses)[a]	60	1,484	53	—	—	1,597
Profit (loss) before interest and taxation	634	6,646	643	(8,157)	(196)	(430)
Finance costs						(1,675)
Net finance expense relating to pensions and other post-retirement benefits						(190)
Profit (loss) before taxation						(2,295)
Other income statement items						
Depreciation, depletion and amortization						
US	4,396	856	—	71	—	5,323
Non-US	7,835	1,094	—	253	—	9,182
Charges for provisions, net of write-back of unused provisions, including change in discount rate	352	758	—	6,719	—	7,829

[a] See explanation of inventory holding gains and losses on page 156.

By geographical area	**US**	**Non-US**	**Total**
			$ million
			2018
Revenues			
Third party sales and other operating revenues[a]	**98,066**	**200,690**	**298,756**
Other income statement items			
Production and similar taxes	**369**	**1,167**	**1,536**
Results			
Replacement cost profit (loss) before interest and taxation	**3,041**	**17,138**	**20,179**
Non-current assets			
Non-current assets[b c]	**68,188**	**124,060**	**192,248**

[a] Non-US region includes UK $65,630 million
[b] Non-US region includes UK $19,426 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	Total
			$ million
			2017
Revenues			
Third party sales and other operating revenues[a]	83,269	156,939	240,208
Other income statement items			
Production and similar taxes	52	1,723	1,775
Results			
Replacement cost profit (loss) before interest and taxation	(266)	8,887	8,621
Non-current assets			
Non-current assets[b c]	61,828	123,646	185,474

[a] Non-US region includes UK $48,837 million.
[b] Non-US region includes UK $18,004 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

5. Segmental analysis – continued

By geographical area	US	Non-US	Total
			$ million
			2016
Revenues			
Third party sales and other operating revenues[a]	65,132	117,876	183,008
Other income statement items			
Production and similar taxes	155	528	683
Results			
Replacement cost profit (loss) before interest and taxation	(8,311)	6,284	(2,027)

[a] Non-US region includes UK $37,119 million.

6. Revenue from contracts with customers

The amounts shown in the table below are included in Sales and other operating revenues in the group income statement. An analysis of total sales and other operating revenues by segment and region is provided in Note 5.

Revenue from contracts with customers, by product

			$ million
	2018	2017	2016
Crude oil	**65,276**	49,670	32,284
Oil products	**195,466**	159,821	126,465
Natural gas, LNG and NGLs	**21,745**	16,196	11,337
Non-oil products and other revenues from contracts with customers	**13,768**	12,538	11,487
Revenues from contracts with customers	**296,255**	238,225	181,573

The group's sales to customers of crude oil and oil products were substantially all made by the Downstream segment. The group's sales to customers of natural gas, LNG and NGLs were made by the Upstream segment. A significant majority of the group's sales of non-oil products and other revenues from contracts with customers were made by the Downstream segment.

7. Income statement analysis

			$ million
	2018	2017	2016
Interest and other income			
Interest income from			
Financial assets measured at amortized cost	**421**	288	183
Financial assets measured at fair value through profit or loss	**39**	—	—
Other income	**313**	369	323
	773	657	506
Currency exchange losses charged to the income statement[a]	**368**	83	698
Expenditure on research and development	**429**	391	400
Finance costs			
Interest payable on liabilities measured at amortized cost	**2,198**	1,718	1,221
Capitalized at 3.56% (2017 2.25% and 2016 1.81%)[b]	**(419)**	(297)	(244)
Unwinding of discount on provisions	**210**	150	310
Unwinding of discount on other payables measured at amortized cost	**539**	503	388
	2,528	2,074	1,675

[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 $55 million (2017 $64 million and 2016 $56 million).

8. 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 judgements made in relation to oil and natural gas accounting see Intangible assets in Note 1.

			$ million
	2018	2017	2016
Exploration and evaluation costs			
Exploration expenditure written off[a]	**1,085**	1,603	1,274
Other exploration costs	**360**	477	447
Exploration expense for the year	**1,445**	2,080	1,721
Impairment losses	**137**	—	62
Intangible assets – exploration and appraisal expenditure[b]	**15,989**	17,026	16,960
Liabilities	**60**	82	102
Net assets	**15,929**	16,944	16,858
Cash used in operating activities	**360**	477	447
Cash used in investing activities	**1,119**	1,901	2,920

[a] 2018 includes $447 million in the deepwater Gulf of Mexico principally relating to licence expiries. 2017 included a write-off in Angola of $574 million in relation to licence relinquishment, and Egypt of $208 million following a determination that no commercial hydrocarbons had been found. 2017 also included a $145-million write-off in relation to the value ascribed to certain licences in the deepwater Gulf of Mexico as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011. 2016 included a $601-million write-off in Brazil relating to the BM-C-34 licence and various write-offs in the Gulf of Mexico totalling $611 million and India totalling $216 million, partially offset by a write-back of $319 million in India relating to block KG D6 as a result of increased confidence in the progress of the projects. An impairment reversal of $234 million was also recorded in 2016 in relation to KG D6 in India. For further information see Upstream – Exploration on page 25.

[b] 2018 includes $2.3 billion relating to licences in the Gulf of Mexico that have expired and approximately $1.6 billion relating to certain licences elsewhere that are due to expire in the next financial year. BP remains committed to developing these prospects. See Note 1 for further information.

The carrying amount, by location, of exploration and appraisal expenditure capitalized as intangible assets at 31 December 2018 is shown in the table below.

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

9. Taxation

Tax on profit

			$ million
	2018	2017	2016
Current tax			
Charge for the year	**6,217**	4,208	1,762
Adjustment in respect of prior years[a]	**(221)**	58	(123)
	5,996	4,266	1,639
Deferred tax[b]			
Origination and reversal of temporary differences in the current year	**907**	(503)	(3,709)
Adjustment in respect of prior years	**242**	(51)	(397)
	1,149	(554)	(4,106)
Tax charge (credit) on profit or loss	**7,145**	3,712	(2,467)

[a] The adjustments in respect of prior years reflect the reassessment of the current tax balances for prior years in light of changes in facts and circumstances during the year.

[b] Origination and reversal of temporary differences in the current year include the impact of tax rate changes on deferred tax balances. 2018 includes a credit of $121 million (2017 $859 million charge) in respect of the reduction in the US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018. The adjustments in respect of prior years reflect the reassessment of deferred tax balances for prior periods in light of all other changes in facts and circumstances during the year.

In 2018, the total tax charge recognized within other comprehensive income was $714 million (2017 $1,499 million charge and 2016 $752 million credit), primarily comprising the deferred tax impact of the remeasurements of the net pension and other post-retirement benefit liability or asset. See Note 32 for further information.

The total tax charge recognized directly in equity was $17 million (2017 $263 million charge and 2016 $5 million credit).

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

Reconciliation of the effective tax rate

The following table provides a reconciliation of the group weighted average statutory corporate income tax rate to the effective tax rate of the group on profit or loss before taxation.

For 2016, 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 reversals, and for the impacts of the Gulf of Mexico oil spill and impairment losses and reversals in isolation.

9. Taxation – continued

	2018	2017	2016 excluding impacts of Gulf of Mexico oil spill and impairments	2016 impacts of Gulf of Mexico oil spill and impairments	2016
					$ million
Profit (loss) before taxation	**16,723**	7,180	2,914	(5,209)	(2,295)
Tax charge (credit) on profit or loss	**7,145**	3,712	(117)	(2,350)	(2,467)
Effective tax rate	**43%**	52%	(4)%	45%	107%

					% of profit or loss before taxation
Tax rate computed at the weighted average statutory rate[a]	**43**	44	18	33	52
Increase (decrease) resulting from					
Tax reported in equity-accounted entities	**(5)**	(7)	(15)	—	19
Adjustments in respect of prior years	**—**	—	5	13	23
Deferred tax not recognized	**2**	9	26	3	(27)
Tax incentives for investment	**(2)**	(6)	(9)	—	11
Gulf of Mexico oil spill non-deductible costs	**—**	1	—	(2)	(4)
Disposal impacts[b]	**—**	(1)	(24)	—	30
Foreign exchange	**3**	(4)	1	—	(2)
Items not deductible for tax purposes	**1**	5	8	—	(11)
Impact of US tax reform[c]	**(1)**	12	—	—	—
Decrease in rate of UK supplementary charge[d]	**—**	—	(15)	—	19
Other	**2**	(1)	1	(2)	(3)
Effective tax rate	**43**	52	(4)	45	107

[a] Calculated based on the statutory corporate income tax rate applicable in the countries in which the group operates, weighted by the profits and losses before tax in the respective countries.

[b] In 2016 this related primarily to the tax impact on the contribution of BP's Norwegian upstream business into Aker BP ASA.

[c] Relates to the deferred tax impact of the reduction in the US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018.

[d] Relates to the deferred tax impact of the reduction in the UK supplementary charge rate applicable to profits arising in the North Sea from 20% to 10% in 2016.

Deferred tax

Analysis of movements during the year in the net deferred tax liability	2018	2017
		$ million
At 31 December	**3,513**	2,497
Adjustment on adoption of IFRS 9[a]	**(36)**	—
At 1 January	**3,477**	2,497
Exchange adjustments	**(68)**	12
Charge (credit) for the year in the income statement	**1,149**	(554)
Charge for the year in other comprehensive income	**734**	1,503
Charge for the year in equity	**17**	1
Acquisitions and other additions[b]	**797**	54
At 31 December	**6,106**	3,513

[a] 2018 reflects the deferred tax impact of adjustments recorded by the group on adoption of IFRS 9. See Note 1 for further information.

[b] 2018 relates primarily to the purchase of an additional 16.5% interest in the Clair field. See Note 3 - Other significant transactions for further information.

9. Taxation – continued

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[a]		Balance sheet[a]
	2018	2017	2016	**2018**	2017
Deferred tax liability					
Depreciation	**(1,297)**	(3,971)	81	**22,565**	23,045
Pension plan surpluses	**65**	(12)	(12)	**1,956**	1,319
Derivative financial instruments	**(36)**	(27)	(230)	**—**	623
Other taxable temporary differences	**(57)**	(64)	(122)	**1,224**	1,317
	(1,325)	(4,074)	(283)	**25,745**	26,304
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**(6)**	340	98	**(1,319)**	(1,386)
Decommissioning, environmental and other provisions	**1,505**	3,503	591	**(7,126)**	(8,618)
Derivative financial instruments	**(25)**	(50)	(6)	**(144)**	(672)
Tax credits[b]	**123**	1,476	(5,177)	**(3,626)**	(3,750)
Loss carry forward	**559**	(964)	249	**(5,900)**	(6,493)
Other deductible temporary differences	**318**	(785)	422	**(1,524)**	(1,872)
	2,474	3,520	(3,823)	**(19,639)**	(22,791)
Net deferred tax charge (credit) and net deferred tax liability	**1,149**	(554)	(4,106)	**6,106**	3,513
Of which – deferred tax liabilities				**9,812**	7,982
– deferred tax assets				**3,706**	4,469

[a] The 2017 and 2018 income statement and balance sheet are impacted by the reduction in US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018.

[b] The 2016 income statement reflected the impact of a loss carry-back claim in the US, displacing foreign tax credits utilized in prior periods which are now carried forward.

The recognition of deferred tax assets of $2,758 million (2017 $3,503 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. For 2018, $1,563 million relates to the US (2017 $2,067 million) and $1,108 million relates to India (2017 $1,336 million).

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	**2018**	2017
Unused US state tax losses[a]	**6.6**	6.8
Unused tax losses – other jurisdictions[b]	**4.3**	4.5
Unused tax credits	**22.5**	20.1
of which – arising in the UK[c]	**18.7**	16.3
– arising in the US[d]	**3.8**	3.8
Deductible temporary differences[e]	**37.3**	31.4
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	**1.5**	1.6

[a] For 2018 these losses expire in the period 2019-2038 with applicable tax rates ranging from 3% to 12%.

[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 higher statutory corporate income tax rates than the UK. 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 in respect of overseas tax. These tax credits have no fixed expiry date.

[d] For 2018 the US unused tax credits expire in the period 2019-2028.

[e] The majority comprises fixed asset temporary differences in the UK. 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 tax charge	**2018**	2017	2016
Current tax benefit relating to the utilization of previously unrecognized deferred tax assets	**83**	22	40
Deferred tax benefit arising from the reversal of a previous write-down of deferred tax assets	**—**	—	269
Deferred tax benefit relating to the recognition of previously unrecognized deferred tax assets	**112**	436	394
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	**169**	78	55

10. Dividends

The quarterly dividend paid on 29 March 2019 in respect of the fourth quarter 2018 was 10.25 cents per ordinary share ($0.615 per American Depositary Share (ADS)). The corresponding amount in sterling was announced on 18 March 2019. 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		
	2018	2017	2016	**2018**	2017	2016	**2018**	2017	2016
Dividends announced and paid in cash									
Preference shares							**1**	1	1
Ordinary shares									
March	**7.1691**	8.1587	7.0125	**10.00**	10.00	10.00	**1,828**	1,303	1,099
June	**7.4435**	7.7563	6.9167	**10.00**	10.00	10.00	**1,727**	1,546	1,168
September	**7.9296**	7.6213	7.5578	**10.25**	10.00	10.00	**1,409**	1,676	1,161
December	**8.0251**	7.4435	7.9313	**10.25**	10.00	10.00	**1,734**	1,627	1,182
	30.5673	30.9798	29.4183	**40.50**	40.00	40.00	**6,699**	6,153	4,611
Dividend announced, paid in March 2019				**10.25**			**1,435**		

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

	2018	2017	2016
Number of shares issued (thousand)	**195,305**	289,789	548,005
Value of shares issued ($ million)	**1,381**	1,714	2,858

The financial statements for the year ended 31 December 2018 do not reflect the dividend announced on 5 February 2019 and paid in March 2019; this will be treated as an appropriation of profit in the year ending 31 December 2019.

11. Earnings per share

			Cents per share
Per ordinary share	**2018**	2017	2016
Basic earnings per share	**46.98**	17.20	0.61
Diluted earnings per share	**46.67**	17.10	0.60

			Dollars per share
Per American Depositary Share (ADS)	**2018**	2017	2016
Basic earnings per share	**2.82**	1.03	0.04
Diluted earnings per share	**2.80**	1.03	0.04

Basic earnings per ordinary share amounts are calculated by dividing the profit (loss) for the year attributable to BP 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. 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.

			$ million
	2018	2017	2016
Profit (loss) attributable to BP shareholders	**9,383**	3,389	115
Less: dividend requirements on preference shares	**1**	1	1
Profit (loss) for the year attributable to BP ordinary shareholders	**9,382**	3,388	114

			Shares thousand
	2018	2017	2016
Basic weighted average number of ordinary shares	**19,970,215**	19,692,613	18,744,800
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**132,278**	123,829	110,519
Weighted average number of ordinary shares outstanding used to calculate diluted earnings per share	**20,102,493**	19,816,442	18,855,319

			Shares thousand
	2018	2017	2016
Basic weighted average number of ordinary shares – ADS equivalent	**3,328,369**	3,282,102	3,124,133
Potential dilutive effect of ordinary shares (ADS equivalent) issuable under employee share-based payment plans	**22,046**	20,638	18,420
Weighted average number of ordinary shares (ADS equivalent) outstanding used to calculate diluted earnings per share	**3,350,415**	3,302,740	3,142,553

11. Earnings per share – continued

The number of ordinary shares outstanding at 31 December 2018, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 20,101,658,664. Between 31 December 2018 and 11 March 2019, the latest practicable date before the completion of these financial statements, there was a net increase of 143,038,241 in the number of ordinary shares outstanding primarily 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 87-109.

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		2018		2017
	Number of options[ab] thousand	**Weighted average exercise price $**	Number of options[ab] thousand	Weighted average exercise price $
Outstanding	**19,437**	**4.28**	22,399	4.34
Exercisable	**481**	**4.69**	1,112	4.46
Dilutive effect	**6,123**	**n/a**	5,145	n/a

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

[b] At 31 December 2018 the quoted market price of one BP ordinary share was £4.96 (2017 £5.23).

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	2018	2017
Vesting	**Number of shares[a] thousand**	Number of shares[a] thousand
Within one year	**108,934**	101,550
1 to 2 years	**106,337**	108,373
2 to 3 years	**71,407**	85,878
3 to 4 years	**588**	413
Over 4 years	**799**	166
	288,065	296,380
Dilutive effect	**127,165**	126,122

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

There has been a net decrease of 56,796,490 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2018 and 11 March 2019.

12. Property, plant and equipment

$ million

	Land and land improvements	Buildings	Oil and gas properties[a]	Plant, machinery and equipment	Fittings, fixtures and office equipment	Transportation[b]	Oil depots, storage tanks and service stations	Total
Cost								
At 1 January 2018	**3,474**	**1,573**	**226,054**	**46,662**	**2,853**	**10,774**	**8,748**	**300,138**
Exchange adjustments	**(168)**	**(58)**	**—**	**(892)**	**(73)**	**(43)**	**(501)**	**(1,735)**
Additions	**233**	**40**	**9,712**	**2,323**	**204**	**(112)**	**736**	**13,136**
Acquisitions	**163**	**4**	**10,882**	**9**	**1**	**2**	**36**	**11,097**
Remeasurements	**—**	**—**	**17**	**—**	**—**	**—**	**—**	**17**
Transfers from intangible assets	**—**	**—**	**901**	**—**	**—**	**—**	**—**	**901**
Deletions	**(140)**	**(45)**	**(14,699)**	**(1,810)**	**(238)**	**(128)**	**(146)**	**(17,206)**
At 31 December 2018	**3,562**	**1,514**	**232,867**	**46,292**	**2,747**	**10,493**	**8,873**	**306,348**
Depreciation								
At 1 January 2018	**683**	**818**	**133,326**	**20,996**	**2,136**	**7,523**	**5,185**	**170,667**
Exchange adjustments	**(25)**	**(24)**	**—**	**(460)**	**(52)**	**(27)**	**(279)**	**(867)**
Charge for the year	**92**	**52**	**12,342**	**1,820**	**189**	**252**	**384**	**15,131**
Impairment losses	**2**	**—**	**86**	**253**	**—**	**178**	**2**	**521**
Impairment reversals	**—**	**—**	**(564)**	**(1)**	**—**	**(17)**	**—**	**(582)**
Deletions	**(126)**	**(139)**	**(11,333)**	**(1,733)**	**(232)**	**(75)**	**(145)**	**(13,783)**
At 31 December 2018	**626**	**707**	**133,857**	**20,875**	**2,041**	**7,834**	**5,147**	**171,087**
Net book amount at 31 December 2018	**2,936**	**807**	**99,010**	**25,417**	**706**	**2,659**	**3,726**	**135,261**
Cost								
At 1 January 2017	3,066	2,235	215,564	43,725	2,670	14,000	7,623	288,883
Exchange adjustments	264	42	—	1,251	91	28	772	2,448
Additions	264	94	12,366	1,890	240	347	575	15,776
Acquisitions	—	—	—	41	—	228	1	270
Transfers from intangible assets	—	—	451	—	—	—	—	451
Deletions	(120)	(798)	(2,327)	(245)	(148)	(3,829)	(223)	(7,690)
At 31 December 2017	3,474	1,573	226,054	46,662	2,853	10,774	8,748	300,138
Depreciation								
At 1 January 2017	584	1,062	122,428	18,686	2,022	9,823	4,521	159,126
Exchange adjustments	33	27	—	647	67	19	466	1,259
Charge for the year	90	94	12,385	1,764	185	381	350	15,249
Impairment losses	3	35	624	35	—	479	17	1,193
Impairment reversals	—	—	(135)	—	—	(72)	—	(207)
Deletions	(27)	(400)	(1,976)	(136)	(138)	(3,107)	(169)	(5,953)
At 31 December 2017	683	818	133,326	20,996	2,136	7,523	5,185	170,667
Net book amount at 31 December 2017	2,791	755	92,728	25,666	717	3,251	3,563	129,471
Assets held under finance leases at net book amount included above								
At 31 December 2018	**—**	**2**	**12**	**207**	**—**	**295**	**6**	**522**
At 31 December 2017	—	2	16	238	—	233	7	496
Assets under construction included above								
At 31 December 2018								**22,522**
At 31 December 2017								23,789

[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.

[b] Includes adjustments to decommissioning provisions see Note 1 for further information.

13. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2018 amounted to $8,319 million (2017 $11,340 million). BP has capital commitments amounting to $1,227 million (2017 $1,451 million) in relation to associates. BP's share of capital commitments of joint ventures amounted to $619 million (2017 $483 million).

14. Goodwill and impairment review of goodwill

		$ million
	2018	2017
Cost		
At 1 January	**12,163**	11,805
Exchange adjustments	**(210)**	336
Acquisitions and other additions[a]	**1,046**	83
Deletions	**(184)**	(61)
At 31 December	**12,815**	12,163
Impairment losses		
At 1 January	**612**	611
Exchange adjustments	**—**	1
Deletions	**(1)**	—
At 31 December	**611**	612
Net book amount at 31 December	**12,204**	11,551
Net book amount at 1 January	**11,551**	11,194

[a] 2018 principally relates to the purchase of an additional 16.5% share in the Clair field in the North Sea. See Note 3 - Other significant transactions for further information.

Impairment review of goodwill

		$ million
Goodwill at 31 December	**2018**	2017
Upstream	**8,346**	7,728
Downstream	**3,802**	3,758
Other businesses and corporate	**56**	65
	12,204	11,551

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, intangible assets and goodwill in Note 1.

Upstream

		$ million
	2018	2017
Goodwill	**8,346**	7,728
Excess of recoverable amount over carrying amount	**53,391**	27,705

The table above shows the carrying amount of goodwill for the segment and the excess of the recoverable amount, based upon a post-tax value-in-use calculation, over the carrying amount (headroom) at the date of the test. The increase in headroom principally arises from acquisitions, new activity and changes in US tax. In the prior year, the recoverable amount was estimated using a fair value less costs of disposal calculation and was based on cash flows estimated for the impairment test performed in 2016 as permitted by IAS 36.

The value in use 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. As the production profile and related cash flows can be estimated from BP's past experience, management believes that the cash flows generated over the estimated life of field is the appropriate basis upon which to assess goodwill and individual assets 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 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.

The most recent review for impairment was carried out in the fourth quarter. The key assumptions used in the value-in-use calculation are oil and natural gas prices, production volumes and the discount rate. Oil and gas price assumptions for the first five years are based on management's best estimate of prices over those five years, with the long-term price applied from year 6 onwards. Price assumptions and discount rate assumptions used were as disclosed in Note 1. The value-in-use calculation has 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.

Sensitivities to different variables have been estimated using certain simplifying assumptions. For example, lower oil and gas price 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.

14. Goodwill and impairment review of goodwill – continued

It is estimated that if the oil price assumption for all future years was approximately $14 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 no reasonable fall in the gas price assumption 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 829mmboe per year (2017 889mmboe per year). It is estimated that if production volumes were to be reduced by approximately 13% for this period, 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 post-tax discount rate was approximately 11% for the entire portfolio, an increase of 5% for all countries not considered 'higher risk' and 3% for countries considered 'higher risk', this would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the segment.

Downstream

						$ million
			2018			2017
	Lubricants	Other	Total	Lubricants	Other	Total
Goodwill	**2,692**	**1,110**	**3,802**	2,849	909	3,758

Cash flows for each cash-generating unit are derived from the business segment plans, which cover a period of up 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 as the basis for the tests in 2014-2017 as the criteria of IAS 36 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 is remote. IAS 36 does not specify for how many years such an approach is appropriate and management determined that a re-performance of the test was appropriate in 2018 given the passage of time since 2013. There was no significant change in the outcome of this test compared to that in 2013.

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. Operating margin and sales volumes assumptions used in the detailed impairment review of goodwill calculation are consistent with the assumptions used in the Lubricants unit's business plan and values assigned to these key assumptions reflect past 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 plan period are extrapolated using a nominal 2.8% growth rate (2013 3%).

15. Intangible assets

						$ million
			2018			2017
	Exploration and appraisal expenditure[a]	Other intangibles	Total	Exploration and appraisal expenditure[a]	Other intangibles	Total
Cost						
At 1 January	**17,886**	**4,488**	**22,374**	18,524	4,035	22,559
Exchange adjustments	**—**	**(128)**	**(128)**	—	197	197
Acquisitions	**—**	**25**	**25**	—	41	41
Additions	**1,095**	**318**	**1,413**	2,128	310	2,438
Transfers to property, plant and equipment	**(901)**	**—**	**(901)**	(451)	—	(451)
Deletions	**(1,027)**	**(199)**	**(1,226)**	(2,315)	(95)	(2,410)
At 31 December	**17,053**	**4,504**	**21,557**	17,886	4,488	22,374
Amortization						
At 1 January	**860**	**3,159**	**4,019**	1,564	2,812	4,376
Exchange adjustments	**—**	**(77)**	**(77)**	—	107	107
Charge for the year	**1,085**	**326**	**1,411**	1,603	335	1,938
Impairment losses	**137**	**—**	**137**	—	—	—
Deletions	**(1,018)**	**(199)**	**(1,217)**	(2,307)	(95)	(2,402)
At 31 December	**1,064**	**3,209**	**4,273**	860	3,159	4,019
Net book amount at 31 December	**15,989**	**1,295**	**17,284**	17,026	1,329	18,355
Net book amount at 1 January	**17,026**	**1,329**	**18,355**	16,960	1,223	18,183

[a] For further information see Intangible assets within Note 1 and Note 8.

16. Investments in joint ventures

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

			$ million
	2018	2017	2016
Sales and other operating revenues	**13,258**	11,380	10,081
Profit before interest and taxation	**1,396**	1,394	1,612
Finance costs	**85**	100	156
Profit before taxation	**1,311**	1,294	1,456
Taxation	**414**	117	490
Profit for the year	**897**	1,177	966
Other comprehensive income	**6**	8	5
Total comprehensive income	**903**	1,185	971
Non-current assets	**10,399**	10,139	
Current assets	**2,935**	2,419	
Total assets	**13,334**	12,558	
Current liabilities	**1,715**	1,687	
Non-current liabilities	**3,017**	2,927	
Total liabilities	**4,732**	4,614	
Net assets	**8,602**	7,944	
Group investment in joint ventures			
Group share of net assets (as above)	**8,602**	7,944	
Loans made by group companies to joint ventures	**45**	50	
	8,647	7,994	

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

						$ million
Sales to joint ventures		**2018**		2017		2016
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	**4,603**	**251**	3,578	352	3,327	291

						$ million
Purchases from joint ventures		**2018**		2017		2016
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	**1,336**	**300**	1,257	176	943	120

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.

17. 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
	2018	2017	2016	**2018**	2017
Rosneft	**2,283**	922	647	**10,074**	10,059
Other associates	**573**	408	347	**7,599**	6,932
	2,856	1,330	994	**17,673**	16,991

The associate that is material to the group at both 31 December 2018 and 2017 is Rosneft.

BP owns 19.75% of the voting shares of Rosneft which 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 JSC Rosneftegaz, owned 50.0% plus one share of the voting shares of Rosneft at 31 December 2018.

BP classifies its investment in Rosneft as an associate because, in management's judgement, BP has significant influence over Rosneft; see Interests in other entities within Note 1 for further information. The group's investment in Rosneft is a foreign operation whose functional currency is the Russian rouble. The increase in the group's equity-accounted investment balance for Rosneft at 31 December 2018 compared with 31 December 2017 principally relates to earnings from Rosneft offset by dividends distribution and foreign exchange effects which have been recognized in other comprehensive income.

17. Investments in associates – continued

The value of BP's 19.75% shareholding in Rosneft based on the quoted market share price of $6.18 per share (2017 $4.99 per share) was $12,934 million at 31 December 2018 (2017 $10,444 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 2018, as shown in the table below, compared with the amounts reported in Rosneft's IFRS financial statements. In particular, in 2018 these adjustments resulted in BP reporting a lower amount relating to impairment charges of downstream goodwill than the equivalent amounts reported by Rosneft.

			$ million
			Gross amount
	2018	2017	2016
Sales and other operating revenues	**131,322**	103,028	74,380
Profit before interest and taxation	**18,886**	9,949	7,094
Finance costs	**2,785**	2,228	1,747
Profit before taxation	**16,101**	7,721	5,347
Taxation	**2,957**	1,742	1,797
Non-controlling interests	**1,585**	1,311	273
Profit for the year	**11,559**	4,668	3,277
Other comprehensive income	**2,086**	2,810	4,203
Total comprehensive income	**13,645**	7,478	7,480
Non-current assets	**137,038**	158,719	
Current assets	**43,438**	39,737	
Total assets	**180,476**	198,456	
Current liabilities	**41,311**	66,506	
Non-current liabilities	**78,754**	70,704	
Total liabilities	**120,065**	137,210	
Net assets	**60,411**	61,246	
Less: non-controlling interests	**9,403**	10,314	
	51,008	50,932	

The group received dividends, net of withholding tax, of $620 million from Rosneft in 2018 (2017 $314 million and 2016 $332 million).

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

									$ million
									BP share
			2018			2017			2016
	Rosneft[a]	**Other**	**Total**	Rosneft[a]	Other	Total	Rosneft[a]	Other	Total
Sales and other operating revenues	**25,936**	**9,134**	**35,070**	20,348	7,600	27,948	14,690	5,377	20,067
Profit before interest and taxation	**3,730**	**1,150**	**4,880**	1,965	626	2,591	1,401	525	1,926
Finance costs	**550**	**78**	**628**	440	54	494	345	22	367
Profit before taxation	**3,180**	**1,072**	**4,252**	1,525	572	2,097	1,056	503	1,559
Taxation	**584**	**499**	**1,083**	344	164	508	355	156	511
Non-controlling interests	**313**	**—**	**313**	259	—	259	54	—	54
Profit for the year	**2,283**	**573**	**2,856**	922	408	1,330	647	347	994
Other comprehensive income	**412**	**(1)**	**411**	555	1	556	830	(2)	828
Total comprehensive income	**2,695**	**572**	**3,267**	1,477	409	1,886	1,477	345	1,822
Non-current assets	**27,065**	**10,787**	**37,852**	31,347	9,261	40,608			
Current assets	**8,579**	**2,398**	**10,977**	7,848	2,645	10,493			
Total assets	**35,644**	**13,185**	**48,829**	39,195	11,906	51,101			
Current liabilities	**8,159**	**2,232**	**10,391**	13,135	2,501	15,636			
Non-current liabilities	**15,554**	**3,817**	**19,371**	13,964	3,308	17,272			
Total liabilities	**23,713**	**6,049**	**29,762**	27,099	5,809	32,908			
Net assets	**11,931**	**7,136**	**19,067**	12,096	6,097	18,193			
Less: non-controlling interests	**1,857**	**—**	**1,857**	2,037	—	2,037			
	10,074	**7,136**	**17,210**	10,059	6,097	16,156			
Group investment in associates									
Group share of net assets (as above)	**10,074**	**7,136**	**17,210**	10,059	6,097	16,156			
Loans made by group companies to associates	**—**	**463**	**463**	—	835	835			
	10,074	**7,599**	**17,673**	10,059	6,932	16,991			

[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.

17. Investments in associates – continued

Transactions between the group and its associates are summarized below.

						$ million
Sales to associates		**2018**		2017		2016
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	**2,064**	**393**	1,612	216	3,643	765

						$ million
Purchases from associates		**2018**		2017		2016
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	**14,112**	**2,069**	11,613	1,681	8,873	2,000

In addition to the transactions shown in the table above, in 2018 BP acquired a 49% stake in LLC Kharampurneftegaz, a Rosneft subsidiary, which will develop subsoil resources within the Kharampurskoe and Festivalnoye licence areas in Yamalo-Nenets Autonomous Okrug in northern Russia. BP's interest in LLC Kharampurneftegaz is accounted for as an associate.

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 $11,303 million (2017 $13,932 million), primarily in relation to contracts with its associates for the purchase of transportation capacity. For information on capital commitments in relation to associates see Note 13.

18. Other investments

				$ million
		2018		2017
	Current	**Non-current**	Current	Non-current
Equity investments[a]	**1**	**482**	15	418
Other	**221**	**859**	110	827
	222	**1,341**	125	1,245

[a] The majority of equity investments are unlisted.

Other investments includes $893 million relating to contingent consideration amounts arising on disposals (2017 $237 million) which are financial assets classified as measured at fair value through profit or loss. The fair value is determined using an estimate of discounted future cash flows that are expected to be received and is considered a level 3 valuation under the fair value hierarchy. Future cash flows are estimated based on inputs including oil and natural gas prices, production volumes and operating costs related to the disposed operations. The discount rate used is based on a risk-free rate adjusted for asset-specific risks.

19. Inventories

		$ million
	2018	2017
Crude oil	**4,878**	5,692
Natural gas	**322**	119
Refined petroleum and petrochemical products	**10,419**	10,694
	15,619	16,505
Trading inventories	**282**	295
	15,901	16,800
Supplies	**2,087**	2,211
	17,988	19,011
Cost of inventories expensed in the income statement	**229,878**	179,716

The inventory valuation at 31 December 2018 is stated net of a provision of $1,009 million (2017 $474 million) to write down inventories to their net realizable value, of which $604 million (2017 $62 million) relates to hydrocarbon inventories. The net charge to the income statement in the year in respect of inventory net realizable value provisions was $552 million (2017 $27 million credit), of which $553 million (2017 $31 million credit) related to hydrocarbon inventories.

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

20. Trade and other receivables

$ million

	2018		2017	
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**19,414**	**7**	18,912	4
Amounts receivable from joint ventures and associates	**642**	**2**	566	2
Other receivables	**3,275**	**740**	4,206	671
	23,331	**749**	23,684	677
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset	**214**	**—**	252	—
Sales taxes and production taxes	**790**	**482**	746	276
Other receivables	**143**	**603**	167	481
	1,147	**1,085**	1,165	757
	24,478	**1,834**	24,849	1,434

In both 2018 and 2017 the group entered into non-recourse arrangements to discount certain receivables in support of supply and trading activities and the management of credit risk.

Trade and other receivables are predominantly non-interest bearing. See Note 29 for further information.

21. Valuation and qualifying accounts

$ million

	2018				2017		2016	
	Not credit-impaired	**Credit impaired**	**Trade and other receivables**	**Fixed asset investments**	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments
At 1 January – IAS 39	**—**	**335**	**335**	**314**	392	335	447	435
Adjustment on adoption of IFRS 9	**115**	**—**	**115**	**(85)**	—	—	—	—
At 1 January – IFRS 9	**115**	**335**	**450**	**229**	392	335	447	435
Charged to costs and expenses	**(26)**	**56**	**30**	**10**	68	47	120	55
Charged to other accounts[a]	**—**	**(12)**	**(12)**	**(1)**	13	3	(7)	(2)
Deductions	**—**	**(52)**	**(52)**	**(3)**	(138)	(71)	(168)	(153)
At 31 December	**89**	**327**	**416**	**235**	335	314	392	335

[a] Principally exchange adjustments.

Valuation and qualifying accounts relating to trade and other receivables comprise expected credit loss allowances in 2018 and impairment provisions recognized on an incurred loss basis in comparative periods. The adjustment on adoption of IFRS 9 relates to the additional loss allowance required by the new standard's expected credit loss model. There were no significant changes to the gross carrying amounts of trade and other receivables during the year that affected the estimation of the loss allowance at 31 December 2018.

Valuation and qualifying accounts relating to fixed asset investments comprise impairment provisions for investments in equity-accounted entities in 2018. This includes expected credit loss allowances of $44 million (1 January 2018 $43 million) relating to loans that form part of the net investment in equity-accounted entities. The adjustment on adoption of IFRS 9 primarily relates to amounts provided against investments in equity instruments that were held at cost less impairment losses under IAS 39 but that are classified as measured at fair value through profit or loss under IFRS 9.

In addition to the amounts presented above, expected loss allowances on cash and cash equivalents classified as measured at amortized cost totalled $11 million (1 January 2018 $11 million). For further information on the group's credit risk management policies and how the group recognizes and measures expected losses see Note 29.

Valuation and qualifying accounts are deducted in the balance sheet from the assets to which they apply.

For further information on the adjustments on adoption of IFRS 9 see Note 1.

22. Trade and other payables

$ million

	2018		2017	
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**26,252**	**—**	26,983	—
Amounts payable to joint ventures and associates	**2,369**	**—**	1,857	—
Payables for capital expenditure and acquisitions[a]	**7,325**	**1,345**	3,810	1,269
Payables related to the Gulf of Mexico oil spill[b]	**2,279**	**11,922**	2,089	12,253
Other payables	**4,980**	**318**	5,733	60
	43,205	**13,585**	40,472	13,582
Non-financial liabilities				
Sales taxes, customs duties, production taxes and social security	**2,272**	**35**	2,586	50
Other payables	**788**	**210**	1,151	257
	3,060	**245**	3,737	307
	46,265	**13,830**	44,209	13,889

[a] Includes $3,514 million deferred consideration relating to the acquisition of Petrohawk Energy Corporation from BHP Billiton Petroleum (North America) Inc. See Note 3 for further information.

[b] See Note 2 for further information.

Materially all of BP's trade payables have payment terms in the range of 30 to 60 days and give rise to operating cash flows. The active management of supplier payment terms within this range enables BP to optimize and reduce volatility in cash flow.

Trade and other payables, other than those relating to the Gulf of Mexico oil spill, are predominantly interest free. See Note 29 (c) for further information.

23. Provisions

$ million

	Decommissioning	**Environmental**	**Litigation and claims**	**Other**	**Total**
At 1 January 2018	**16,100**	**1,516**	**3,334**	**2,994**	**23,944**
Exchange adjustments	**(135)**	**(9)**	**(3)**	**(84)**	**(231)**
Acquisitions	**295**	**12**	**24**	**5**	**336**
Increase (decrease) in existing provisions	**137**	**428**	**1,492**	**1,303**	**3,360**
Write-back of unused provisions	**(2)**	**(115)**	**(21)**	**(255)**	**(393)**
Unwinding of discount	**162**	**22**	**9**	**17**	**210**
Change in discount rate[a]	**(2,377)**	**(38)**	**(31)**	**(17)**	**(2,463)**
Utilization	**(9)**	**(245)**	**(1,034)**	**(528)**	**(1,816)**
Reclassified to other payables	**(270)**	**(4)**	**(2,051)**	**(37)**	**(2,362)**
Deletions	**(288)**	**—**	**(1)**	**—**	**(289)**
At 31 December 2018	**13,613**	**1,567**	**1,718**	**3,398**	**20,296**
Of which – current	**257**	**300**	**798**	**1,209**	**2,564**
– non-current	**13,356**	**1,267**	**920**	**2,189**	**17,732**
Of which – Gulf of Mexico oil spill[b]	**—**	**—**	**345**	**—**	**345**

[a] Includes the impact of changing from a real to nominal discount rate. See Note 1 for further information.

[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 2018 are provisions for deferred employee compensation of $338 million (2017 $391 million).

For information on significant estimates and judgements made in relation to provisions, see Provisions and contingencies within Note 1.

24. 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 in 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, 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.

24. Pensions and other post-retirement benefits – continued

In the US, all pension benefits now accrue under a cash balance formula. Benefits previously accrued under final salary formulas are legally protected. Retiring 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.

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 based on the interest rate which is set out in German tax law. Retired German employees take their pension benefit typically in the form of an annuity. The German plans are 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 2018 the aggregate level of contributions was $610 million (2017 $637 million and 2016 $651 million). The aggregate level of contributions in 2019 is expected to be approximately $700 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 is agreed covering the next five years. Contractually committed funding amounted to $1,275 million at 31 December 2018, all of which relates to future 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 278.

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. No contributions were made into the primary US pension plan in 2018 and no statutory funding requirement is expected in the next 12 months.

The surplus relating to the primary US fund is recognized on the balance sheet on the basis that economic benefit can be gained from the surplus through a reduction in future contributions.

There was no minimum funding requirement for the US plan, and no significant minimum funding requirements in other countries at 31 December 2018.

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 2018. 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 2017. A valuation of the US plan and largest Eurozone plans are 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
	2018	2017	2016	**2018**	2017	2016	**2018**	2017	2016
Discount rate for plan liabilities	**2.9**	2.5	2.7	**4.1**	3.5	3.9	**2.0**	1.9	1.7
Rate of increase in salaries	**3.8**	4.1	4.6	**3.9**	4.1	4.2	**3.1**	3.0	3.0
Rate of increase for pensions in payment	**3.0**	2.9	3.0	**—**	—	—	**1.5**	1.4	1.5
Rate of increase in deferred pensions	**3.0**	2.9	3.0	**—**	—	—	**0.5**	0.6	0.5
Inflation for plan liabilities	**3.1**	3.1	3.2	**1.5**	1.7	1.8	**1.7**	1.6	1.6

									%
Financial assumptions used to determine benefit expense			UK			US			Eurozone
	2018	2017	2016	**2018**	2017	2016	**2018**	2017	2016
Discount rate for plan service cost	**2.6**	2.7	4.0	**3.6**	4.1	4.2	**2.4**	2.1	2.7
Discount rate for plan other finance expense	**2.5**	2.7	3.9	**3.5**	3.9	4.0	**1.9**	1.7	2.4
Inflation for plan service cost	**3.1**	3.2	3.1	**1.7**	1.8	1.5	**1.6**	1.6	1.8

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 this approach, 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 an allowance for promotion-related salary growth, of up to 0.8% depending on country.

24. Pensions and other post-retirement benefits – continued

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 applicable 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
	2018	2017	2016	**2018**	2017	2016	**2018**	2017	2016
Life expectancy at age 60 for a male currently aged 60	**27.4**	27.4	28.0	**25.1**	25.1	25.7	**25.6**	25.1	25.0
Life expectancy at age 60 for a male currently aged 40	**28.9**	29.0	30.0	**26.9**	26.8	27.5	**28.1**	27.6	27.6
Life expectancy at age 60 for a female currently aged 60	**28.8**	28.8	29.5	**28.5**	28.4	29.3	**29.0**	29.0	28.9
Life expectancy at age 60 for a female currently aged 40	**30.6**	30.5	31.9	**30.1**	30.0	31.0	**31.2**	31.4	31.3

Pension plan assets are generally held in trusts, the primary objective of which is to accumulate assets sufficient to meet the obligations of the plans. 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, 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.

The trustee's long-term investment objective for the primary UK plan as it matures is to invest in assets whose value changes in the same way as the plan liabilities, in order to reduce the level of funding risk. To move towards this objective, the UK plan uses a liability driven investment (LDI) approach for part of the portfolio, investing primarily in government bonds to achieve this matching effect for the most significant plan liability assumptions of interest rate and inflation rate. This is partly funded by short-term sale and repurchase agreements, whereby the plan borrows money using existing bonds as security and which will be bought back at a specified price at an agreed future date. The funds raised are used to invest in further bonds to increase the proportion of assets which match the plan liabilities. The borrowings are shown separately in the analysis of pension plan assets in the table below.

For the primary UK pension plan there is an agreement with the trustee to increase the proportion of assets with liability matching characteristics over time primarily by reducing the proportion of plan assets held as equities and increasing the proportion held as bonds. There is a similar agreement in place for the primary US plan. During 2018, the UK and the US plans switched 12.5% and 10% of plan assets respectively from equities to bonds.

The current asset allocation policy for the major plans at 31 December 2018 was as follows:

	UK	US
Asset category	%	%
Total equity (including private equity)	**30**	**40**
Bonds/cash (including LDI)	**63**	**60**
Property/real estate	**7**	**–**

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2018 were $4,197 million (2017 $2,588 million) of government-issued nominal bonds and $17,491 million (2017 $16,177 million) of index-linked bonds.

Some of the group's pension plans in the Eurozone and other countries use derivative financial instruments as part of their asset mix to manage the level of risk. The fair value of these instruments are included in other assets in the table below. The UK and US plans do not use derivative financial instruments.

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 176.

$ million

	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2018					
Listed equities – developed markets	**5,191**	**1,238**	**413**	**306**	**7,148**
– emerging markets	**950**	**63**	**65**	**56**	**1,134**
Private equity[c]	**2,792**	**1,495**	**—**	**4**	**4,291**
Government issued nominal bonds[d]	**4,263**	**2,072**	**895**	**533**	**7,763**
Government issued index-linked bonds[d]	**17,491**	**—**	**102**	**—**	**17,593**
Corporate bonds[d]	**4,606**	**2,184**	**506**	**243**	**7,539**
Property[e]	**2,311**	**6**	**57**	**25**	**2,399**
Cash	**376**	**73**	**42**	**83**	**574**
Other	**116**	**64**	**32**	**40**	**252**
Debt (repurchase agreements) used to fund liability driven investments	**(6,011)**	**—**	**—**	**—**	**(6,011)**
	32,085	**7,195**	**2,112**	**1,290**	**42,682**
At 31 December 2017					
Listed equities – developed markets	9,548	2,158	537	376	12,619
– emerging markets	2,220	220	83	53	2,576
Private equity[c]	2,679	1,461	—	—	4,140
Government issued nominal bonds[d]	2,663	1,777	941	545	5,926
Government issued index-linked bonds[d]	16,177	—	2	—	16,179
Corporate bonds[d]	4,682	2,024	546	272	7,524
Property[e]	2,211	6	71	30	2,318
Cash	390	80	21	98	589
Other	104	53	23	45	225
Debt (repurchase agreements) used to fund liability driven investments	(5,583)	—	—	—	(5,583)
	35,091	7,779	2,224	1,419	46,513
At 31 December 2016					
Listed equities – developed markets	11,494	2,283	436	363	14,576
– emerging markets	2,549	220	54	46	2,869
Private equity[c]	2,754	1,442	1	—	4,197
Government issued nominal bonds[d]	489	1,438	821	448	3,196
Government issued index-linked bonds[d]	9,384	—	4	—	9,388
Corporate bonds[d]	4,042	1,732	427	259	6,460
Property[e]	1,970	6	45	28	2,049
Cash	547	105	17	83	752
Other	(68)	90	74	83	179
Debt (repurchase agreements) used to fund liability driven investments	(2,981)	—	—	—	(2,981)
	30,180	7,316	1,879	1,310	40,685

[a] Bonds held by the UK pension plans are 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.
[c] Private equity is valued at fair value based on the most recent third-party net asset valuation.
[d] Bonds held by pension plans are valued using quoted prices in active markets. Where quoted prices are not available, quoted prices for similar instruments in active markets are used.
[e] Properties are valued based on an analysis of recent market transactions supported by market knowledge derived from third-party valuers.

24. Pensions and other post-retirement benefits – continued

					$ million
					2018
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	295	299	84	43	721
Past service cost[b]	15	—	9	4	28
Settlement[b]	—	—	17	—	17
Operating charge relating to defined benefit plans	310	299	110	47	766
Payments to defined contribution plans	38	178	5	40	261
Total operating charge	348	477	115	87	1,027
Interest income on plan assets[a]	(868)	(262)	(44)	(45)	(1,219)
Interest on plan liabilities	774	369	136	67	1,346
Other finance (income) expense	(94)	107	92	22	127
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	(722)	(256)	(69)	(36)	(1,083)
Change in financial assumptions underlying the present value of the plan liabilities	1,770	945	14	65	2,794
Change in demographic assumptions underlying the present value of the plan liabilities	123	(9)	(42)	7	79
Experience gains and losses arising on the plan liabilities	520	41	(43)	9	527
Remeasurements recognized in other comprehensive income	1,691	721	(140)	45	2,317
Movements in benefit obligation during the year					
Benefit obligation at 1 January	31,513	10,820	7,275	1,873	51,481
Exchange adjustments	(1,589)	—	(303)	(113)	(2,005)
Operating charge relating to defined benefit plans	310	299	110	47	766
Interest cost	774	369	136	67	1,346
Contributions by plan participants[c]	21	—	2	7	30
Benefit payments (funded plans)[d]	(1,780)	(597)	(84)	(83)	(2,544)
Benefit payments (unfunded plans)[d]	(6)	(218)	(301)	(17)	(542)
Disposals	—	—	—	(14)	(14)
Remeasurements	(2,413)	(977)	71	(81)	(3,400)
Benefit obligation at 31 December[a e]	26,830	9,696	6,906	1,686	45,118
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	35,091	7,779	2,224	1,419	46,513
Exchange adjustments	(1,883)	—	(93)	(73)	(2,049)
Interest income on plan assets[a f]	868	262	44	45	1,219
Contributions by plan participants[c]	21	—	2	7	30
Contributions by employers (funded plans)	490	7	88	25	610
Benefit payments (funded plans)[d]	(1,780)	(597)	(84)	(83)	(2,544)
Disposals	—	—	—	(14)	(14)
Remeasurements[f]	(722)	(256)	(69)	(36)	(1,083)
Fair value of plan assets at 31 December[g]	32,085	7,195	2,112	1,290	42,682
Surplus (deficit) at 31 December	5,255	(2,501)	(4,794)	(396)	(2,436)
Represented by					
Asset recognized	5,473	418	29	35	5,955
Liability recognized	(218)	(2,919)	(4,823)	(431)	(8,391)
	5,255	(2,501)	(4,794)	(396)	(2,436)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	5,473	396	(152)	(97)	5,620
Unfunded	(218)	(2,897)	(4,642)	(299)	(8,056)
	5,255	(2,501)	(4,794)	(396)	(2,436)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(26,612)	(6,799)	(2,264)	(1,387)	(37,062)
Unfunded	(218)	(2,897)	(4,642)	(299)	(8,056)
	(26,830)	(9,696)	(6,906)	(1,686)	(45,118)

[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 and settlements have arisen from restructuring programmes and represent 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 $3,046 million benefits and $2 million settlements, plus $38 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for the US is made up of $7,290 million for pension liabilities and $2,406 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,328 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 174.

24. Pensions and other post-retirement benefits – continued

					$ million
					2017
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	357	292	85	46	780
Past service cost[b]	12	—	5	(1)	16
Settlement[b]	—	—	13	—	13
Operating charge relating to defined benefit plans	369	292	103	45	809
Payments to defined contribution plans	31	191	7	38	267
Total operating charge	400	483	110	83	1,076
Interest income on plan assets[a]	(845)	(266)	(37)	(48)	(1,196)
Interest on plan liabilities	831	393	121	71	1,416
Other finance (income) expense	(14)	127	84	23	220
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	2,396	826	30	43	3,295
Change in financial assumptions underlying the present value of the plan liabilities	(236)	(514)	336	(47)	(461)
Change in demographic assumptions underlying the present value of the plan liabilities	734	72	—	(23)	783
Experience gains and losses arising on the plan liabilities	91	(40)	(36)	14	29
Remeasurements recognized in other comprehensive income	2,985	344	330	(13)	3,646
Movements in benefit obligation during the year					
Benefit obligation at 1 January	29,908	10,533	6,820	1,715	48,976
Exchange adjustments	2,886	—	915	89	3,890
Operating charge relating to defined benefit plans	369	292	103	45	809
Interest cost	831	393	121	71	1,416
Contributions by plan participants[c]	16	—	2	6	24
Benefit payments (funded plans)[d]	(1,903)	(641)	(75)	(89)	(2,708)
Benefit payments (unfunded plans)[d]	(5)	(239)	(302)	(20)	(566)
Acquisitions	—	1	—	—	1
Disposals	—	(1)	(9)	—	(10)
Remeasurements	(589)	482	(300)	56	(351)
Benefit obligation at 31 December[a e]	31,513	10,820	7,275	1,873	51,481
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	30,180	7,316	1,879	1,310	40,685
Exchange adjustments	3,048	—	264	72	3,384
Interest income on plan assets[a f]	845	266	37	48	1,196
Contributions by plan participants[c]	16	—	2	6	24
Contributions by employers (funded plans)	509	12	87	29	637
Benefit payments (funded plans)[d]	(1,903)	(641)	(75)	(89)	(2,708)
Remeasurements[f]	2,396	826	30	43	3,295
Fair value of plan assets at 31 December[g]	35,091	7,779	2,224	1,419	46,513
Surplus (deficit) at 31 December	3,578	(3,041)	(5,051)	(454)	(4,968)
Represented by					
Asset recognized	3,838	260	43	28	4,169
Liability recognized	(260)	(3,301)	(5,094)	(482)	(9,137)
	3,578	(3,041)	(5,051)	(454)	(4,968)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	3,838	238	(106)	(101)	3,869
Unfunded	(260)	(3,279)	(4,945)	(353)	(8,837)
	3,578	(3,041)	(5,051)	(454)	(4,968)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(31,253)	(7,541)	(2,330)	(1,520)	(42,644)
Unfunded	(260)	(3,279)	(4,945)	(353)	(8,837)
	(31,513)	(10,820)	(7,275)	(1,873)	(51,481)

[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 and settlements have arisen from restructuring programmes and represent 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 $3,235 million benefits and $2 million settlements, plus $37 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for the US is made up of $8,085 million for pension liabilities and $2,735 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,586 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 174.

24. Pensions and other post-retirement benefits – continued

	UK	US	Eurozone	Other	$ million 2016 Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	333	310	76	71	790
Past service cost[b]	17	(24)	7	1	1
Settlement	—	—	9	(1)	8
Operating charge relating to defined benefit plans	350	286	92	71	799
Payments to defined contribution plans	30	194	7	33	264
Total operating charge	380	480	99	104	1,063
Interest income on plan assets[a]	(1,086)	(287)	(47)	(51)	(1,471)
Interest on plan liabilities	1,005	417	159	80	1,661
Other finance (income) expense	(81)	130	112	29	190
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	4,422	330	53	8	4,813
Change in financial assumptions underlying the present value of the plan liabilities	(6,932)	(239)	(622)	4	(7,789)
Change in demographic assumptions underlying the present value of the plan liabilities	430	9	12	(5)	446
Experience gains and losses arising on the plan liabilities	55	(62)	26	15	34
Remeasurements recognized in other comprehensive income	(2,025)	38	(531)	22	(2,496)

[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 charges for special termination benefits representing the increased liability arising as a result of early retirements mostly in the UK and Eurozone. The UK also includes $12 million of cost resulting from benefit harmonization within the primary plan.

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 2018 for the group's plans would have had the effects shown in the table below. The effects shown for the expense in 2019 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 2019	**(337)**	**295**
Effect on pension and other post-retirement benefit obligation at 31 December 2018	**(6,179)**	**8,153**
Inflation rate[b]		
Effect on pension and other post-retirement benefit expense in 2019	**227**	**(187)**
Effect on pension and other post-retirement benefit obligation at 31 December 2018	**4,919**	**(4,225)**
Salary growth		
Effect on pension and other post-retirement benefit expense in 2019	**64**	**(55)**
Effect on pension and other post-retirement benefit obligation at 31 December 2018	**653**	**(595)**

[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 2019 pension and other post-retirement benefit expense by $52 million and the pension and other post-retirement benefit obligation at 31 December 2018 by $1,432 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 2028 and the weighted average duration of the defined benefit obligations at 31 December 2018 are as follows:

Estimated future benefit payments	UK	US	Eurozone	Other	$ million Total
2019	**1,030**	**787**	**350**	**101**	**2,268**
2020	**1,036**	**755**	**339**	**97**	**2,227**
2021	**1,056**	**806**	**331**	**97**	**2,290**
2022	**1,088**	**749**	**326**	**100**	**2,263**
2023	**1,120**	**741**	**317**	**98**	**2,276**
2024-2028	**5,777**	**3,476**	**1,501**	**498**	**11,252**
					Years
Weighted average duration	**17.8**	**9.5**	**14.2**	**13.0**	

25. Cash and cash equivalents

	2018	2017
		$ million
Cash	**6,148**	4,592
Term bank deposits	**13,105**	17,324
Cash equivalents (excluding term bank deposits)	**3,215**	3,670
	22,468	25,586

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 2018 includes $1,350 million (2017 $1,488 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 $4,693 million (2017 $3,638 million) of cash and cash equivalents outside the UK and it is not expected that any significant tax will arise on repatriation.

26. Finance debt

						$ million
			2018			2017
	Current	Non-current	Total	Current	Non-current	Total
Borrowings	**9,329**	**55,803**	**65,132**	7,701	54,873	62,574
Net obligations under finance leases	**44**	**623**	**667**	38	618	656
	9,373	**56,426**	**65,799**	7,739	55,491	63,230

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 $7,175 million (2017 $6,849 million) and issued commercial paper of $2,040 million (2017 $744 million). Finance debt does not include accrued interest, which is reported within other payables.

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
						2018
US dollar	**4**	**4**	**17,593**	**4**	**47,465**	**65,058**
Other currencies	**7**	**18**	**657**	**8**	**84**	**741**
			18,250		**47,549**	**65,799**
						2017
US dollar	4	4	18,090	3	44,212	62,302
Other currencies	6	16	895	3	33	928
			18,985		44,245	63,230

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 2018, whereas in the group balance sheet the amount is reported within current finance debt.

The carrying amount of the group's short-term borrowings, comprising mainly of 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 analysis 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
		2018		2017
	Fair value	Carrying amount	Fair value	Carrying amount
Short-term borrowings	**2,153**	**2,153**	852	852
Long-term borrowings	**63,106**	**62,979**	63,182	61,722
Net obligations under finance leases	**1,087**	**667**	1,131	656
Total finance debt	**66,346**	**65,799**	65,165	63,230

27. 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 manage the net debt ratio within a 20-30% band and maintain a significant liquidity buffer. At 31 December 2018, the net debt ratio was 30.3% (2017 27.4%).

		$ million
At 31 December	**2018**	2017
Gross debt	**65,799**	63,230
Less: fair value asset (liability) of hedges related to finance debt[a]	**(813)**	(175)
	66,612	63,405
Less: cash and cash equivalents	**22,468**	25,586
Net debt	**44,144**	37,819
Equity	**101,548**	100,404
Net debt ratio	**30.3%**	27.4 %

[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 $827 million (2017 liability of $634 million, 2016 liability of $1,962 million) are not included in the calculation of net debt shown above as hedge accounting was not applied for these instruments. The movement in the year is attributable to a net cash flow of $nil (2017 net cash outflow $242 million) and fair value losses of $193 million (2017 fair value gains of $1,086 million).

An analysis of changes in net debt is provided below.

								$ million
	2018				2017			
Movement in net debt	**Finance debt**	**Hedge-accounted derivatives**	**Cash and cash equivalents**	**Net debt**	Finance debt	Hedge-accounted derivatives	Cash and cash equivalents	Net debt
At 1 January	**(63,230)**	**(175)**	**25,586**	**(37,819)**	(58,300)	(697)	23,484	(35,513)
Adjustment on adoption of IFRS 9	**—**	**—**	**(11)**	**(11)**	—	—	—	—
Exchange adjustments	**259**	**—**	**(330)**	**(71)**	(1,324)	—	544	(780)
Net financing cash flow	**(3,505)**	**360**	**(2,777)**	**(5,922)**	(2,236)	(284)	1,558	(962)
Fair value gains (losses)	**856**	**(998)**	**—**	**(142)**	(1,314)	1,282	—	(32)
Other movements	**(179)**	**—**	**—**	**(179)**	(56)	(476)	—	(532)
At 31 December	**(65,799)**	**(813)**	**22,468**	**(44,144)**	(63,230)	(175)	25,586	(37,819)

[a] The adjustment on adoption of IFRS 9 reflects the creation of a credit loss allowance for cash and cash equivalents as a result of the new standard`s expected credit loss impairment model.

28. Operating leases

The cost recognized in relation to minimum lease payments for the year was $3,514 million (2017 $4,423 million and 2016 $5,113 million).

The future minimum lease payments at 31 December 2018, before deducting related rental income from operating sub-leases of $120 million (2017 $188 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	**2018**	2017
Payable within		
1 year	**2,511**	2,969
2 to 5 years	**5,359**	6,387
Thereafter	**4,109**	4,614
	11,979	13,970

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

The most significant items of plant and machinery hired under operating leases are drilling rigs used in the Upstream segment. At 31 December 2018, the future minimum lease payments relating to these amounted to $1,378 million (2017 $2,088 million).

28. Operating leases – continued

The group has entered into a number of structured operating leases for ships and in some 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 future minimum lease payments relating to operating leases for international oil and gas ships managed by the BP Shipping function amounted to $3,032 million (2017 $3,172 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. At 31 December 2018, the future minimum lease payments relating to land and buildings amounted to $1,914 million (2017 $2,167 million).

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

BP will adopt IFRS 16 'Leases' in the financial reporting period commencing 1 January 2019. See Note 1 for further details.

29. Financial instruments and financial risk factors

The accounting classification of each category of financial instruments and their carrying amounts are set out below. Current year amounts are presented based on the classification, measurement and impairment requirements of IFRS 9. Comparatives are presented based on the classification, measurement and impairment requirements of IAS 39.

					$ million
At 31 December 2018	Note	Measured at amortized cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
Financial assets					
Other investments	**18**	**—**	**1,563**	**—**	**1,563**
Loans		**839**	**124**	**—**	**963**
Trade and other receivables	**20**	**24,080**	**—**	**—**	**24,080**
Derivative financial instruments	**30**	**—**	**8,564**	**427**	**8,991**
Cash and cash equivalents	**25**	**20,366**	**2,102**	**—**	**22,468**
Financial liabilities					
Trade and other payables	**22**	**(56,790)**	**—**	**—**	**(56,790)**
Derivative financial instruments	**30**	**—**	**(7,685)**	**(1,248)**	**(8,933)**
Accruals		**(5,201)**	**—**	**—**	**(5,201)**
Finance debt	**26**	**(65,799)**	**—**	**—**	**(65,799)**
		(82,505)	**4,668**	**(821)**	**(78,658)**

								$ million
At 31 December 2017	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	18	—	433	—	—	—	—	433
– other	18	—	275	—	662	—	—	937
Loans		836	—	—	—	—	—	836
Trade and other receivables	20	24,361	—	—	—	—	—	24,361
Derivative financial instruments	30	—	—	—	6,454	688	—	7,142
Cash and cash equivalents	25	21,916	2,270	1,400	—	—	—	25,586
Financial liabilities								
Trade and other payables	22	—	—	—	—	—	(54,054)	(54,054)
Derivative financial instruments	30	—	—	—	(5,705)	(864)	—	(6,569)
Accruals		—	—		—	—	(5,465)	(5,465)
Finance debt	26	—	—	—	—	—	(63,230)	(63,230)
		47,113	2,978	1,400	1,411	(176)	(122,749)	(70,023)

The fair value of finance debt is shown in Note 26. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

Information on gains and losses on derivative financial assets and financial liabilities classified as measured at fair value through profit or loss is provided in the derivative gains and losses section of Note 30. Fair value gains and losses related to other assets and liabilities classified as measured at fair value through profit or loss totalled a net loss of $78 million. Dividend income of $8 million from investments in equity instruments classified as measured at fair value through profit or loss is presented within other income - see Note 7.

Interest income and expenses arising on financial instruments are disclosed in Note 7.

29. Financial instruments and financial risk factors – continued

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. Treasury holds foreign exchange and interest-rate products in the financial markets to hedge group exposures related to debt issuance; the compliance, control, and risk management processes for these activities are managed within the treasury function. All other foreign exchange and interest rate activities within financial markets are performed within the integrated supply and trading function and are also underpinned by the compliance, control and risk management infrastructure common to the activities of BP's 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 approves value-at-risk delegations, reviews incidents and validates risk-related policies, methodologies and procedures. A commitments committee approves 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.

(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

Since BP has global operations, fluctuations in foreign currency exchange rates can have a significant effect on the group's reported results and future expenditure commitments. 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.

Most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2018, the total foreign currency borrowings not swapped into US dollars amounted to $741 million (2017 $928 million).

The group manages the net residual foreign currency 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. A continuous assessment is made in respect to the group's foreign currency exposures to capture hedging requirements.

During the year, hedge accounting was applied to foreign currency exposure to highly probable forecast capital expenditure commitments. The group fixes the US dollar cost of non-US dollar supplies by using currency forwards for the highly probable forecast capital expenditure; the exposures are in sterling, euro, Australian dollar, Norwegian krone and Korean won. At 31 December 2018 the most significant open contracts in place were for $434 million sterling (2017 $437 million sterling).

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 in (i) commodity price risk above.

29. Financial instruments and financial risk factors – continued

(iii) Interest rate risk

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 2018 was 72% of total finance debt outstanding (2017 70%). The weighted average interest rate on finance debt at 31 December 2018 was 4% (2017 3%) and the weighted average maturity of fixed rate debt was five years (2017 five 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 changed by one percentage point on 1 January 2019, it is estimated that the group's finance costs for 2019 would change by approximately $475 million (2017 $442 million).

(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 2018 was $696 million (2017 $656 million) in respect of liabilities of joint ventures and associates and $432 million (2017 $382 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.

For the purposes of financial reporting the group calculates expected loss allowances based on the maximum contractual period over which the group is exposed to credit risk. Since this is typically less than 12 months for the group's in-scope financial assets there is no significant difference between the measurement of 12-month and lifetime expected credit losses. The group has no significant financial guarantee liabilities measured on an expected loss basis. Financial assets are considered to be credit-impaired when there is reasonable and supportable evidence that one or more events that have a detrimental impact on the estimated future cash flows of the financial asset have occurred. This includes observable data concerning significant financial difficulty of the counterparty; a breach of contract; concession being granted to the counterparty for economic or contractual reasons relating to the counterparty's financial difficulty, that would not otherwise be considered; it becoming probable that the counterparty will enter bankruptcy or other financial re-organization or an active market for the financial asset disappearing because of financial difficulties. The group also applies a rebuttable presumption that an asset is credit-impaired when contractual payments are more than 30 days past due. Where the group has no reasonable expectation of recovering a financial asset in its entirety or a portion thereof for example where all legal avenues for collection of amounts due have been exhausted, the financial asset (or relevant portion) is written off.

The measurement of expected credit losses is a function of the probability of default, loss given default (i.e. the magnitude of the loss after recovery if there is a default) and the exposure at default (i.e. the asset's carrying amount). The group allocates a credit risk rating to exposures based on data that is determined to be predictive of the risk of loss, including but not limited to external ratings. Probabilities of default derived from historical, current and future-looking market data are assigned by credit risk rating with a loss given default based on historical experience and relevant market and academic research applied by exposure type. Experienced credit judgement is applied to ensure probabilities of default are reflective of the credit risk associated with the group's exposures. Credit enhancements that would reduce the group's credit losses in the event of default are reflected in the calculation when they are considered integral to the related asset.

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 2018, the group had in place credit enhancements designed to mitigate approximately $7.3 billion of credit risk, of which $6.7 billion relates to assets in the scope of IFRS 9's impairment requirements. Credit enhancements include standby and documentary letters of credit, bank guarantees, insurance and liens which are typically taken out with financial institutions who have investment grade credit ratings, or are liens over assets held by the counterparty of the related receivables. 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.

Management information used to monitor credit risk, which reflects the impact of credit enhancements, indicates that the risk profile of financial assets which are subject to review for impairment under IFRS 9 is as set out below.

	%
As at 31 December	2018
AAA to AA-	**22%**
A+ to A-	**41%**
BBB+ to BBB-	**16%**
BB+ to BB-	**8%**
B+ to B-	**11%**
CCC+ and below	**2%**

For the comparative period an analysis of the ageing of trade and other receivables reported under IAS 39 is provided.

29. Financial instruments and financial risk factors – continued

Trade and other receivables at 31 December	$ million 2017
Neither impaired nor past due	22,858
Impaired (net of provision)	53
Not impaired and past due in the following periods	
within 30 days	637
31 to 60 days	130
61 to 90 days	114
over 90 days	569
	24,361

Movements in the impairment provision for trade and other receivables are shown in Note 21.

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 2018	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	**11,502**	**(2,511)**	**8,991**	**(2,079)**	**(299)**	**6,613**
Derivative liabilities	**(11,337)**	**2,511**	**(8,826)**	**2,079**	**—**	**(6,747)**
Trade and other receivables	**11,296**	**(5,390)**	**5,906**	**(1,020)**	**(169)**	**4,717**
Trade and other payables	**(10,797)**	**5,390**	**(5,407)**	**1,020**	**—**	**(4,387)**
At 31 December 2017						
Derivative assets	8,522	(1,380)	7,142	(1,554)	(321)	5,267
Derivative liabilities	(7,818)	1,380	(6,438)	1,554	—	(4,884)
Trade and other receivables	11,648	(5,311)	6,337	(2,156)	(114)	4,067
Trade and other payables	(12,543)	5,311	(7,232)	2,156	—	(5,076)

(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 the treasury function, 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.

BP utilizes various arrangements in order to manage its working capital including discounting of receivables and, in the supply and trading business, the active management of supplier payment terms, inventory and collateral. In line with normal industry practice some supplier arrangements utilize letter of credit (LC) facilities. In certain of those arrangements BP's payments are made to the provider of the LC rather than the supplier.

Standard & Poor's Ratings long-term credit rating for BP is A- (stable outlook) and Moody's Investors Service rating is A1 (stable outlook).

During 2018, $9 billion of long-term taxable bonds were issued with terms ranging from four to ten 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 $22.5 billion at 31 December 2018 (2017 $25.6 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2018, the group had substantial amounts of undrawn borrowing facilities available, consisting of $7,625 million of standby facilities, all of which is available to draw and repay up to the first half of 2022. These facilities are with 25 international banks, and borrowings under them would be at pre-agreed rates.

The group has committed LC facilities totalling $12,175 million with a number of banks, allowing LCs to be issued for a maximum 24-month duration. There were also uncommitted secured LC facilities in place at 31 December 2018 for $4,190 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.

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.

29. Financial instruments and financial risk factors – continued

$ million

	2018				2017			
	Trade and other payables[a]	**Accruals**	**Finance debt**	**Interest on finance debt**	Trade and other payables[a]	Accruals	Finance debt	Interest on finance debt
Within one year	**43,230**	**4,626**	**9,301**	**2,404**	40,472	4,960	7,626	1,757
1 to 2 years	**2,232**	**146**	**6,788**	**1,955**	1,693	135	7,331	1,537
2 to 3 years	**1,662**	**95**	**6,805**	**1,700**	1,413	83	7,068	1,321
3 to 4 years	**1,484**	**64**	**8,057**	**1,422**	1,378	70	6,766	1,114
4 to 5 years	**1,406**	**89**	**7,058**	**1,138**	1,368	54	7,986	894
5 to 10 years	**6,058**	**113**	**25,356**	**2,390**	6,181	115	24,162	1,951
Over 10 years	**5,001**	**68**	**1,243**	**320**	6,125	48	2,089	390
	61,073	**5,201**	**64,608**	**11,329**	58,630	5,465	63,028	8,964

[a] 2018 includes $18,360 million (2017 $18,918 million) in relation to the Gulf of Mexico oil spill.

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 30. 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 finance 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 $22,453 million at 31 December 2018 (2017 $21,484 million) to be received on the same day as the related cash outflows. For further information on our derivative financial instruments, see Note 30.

$ million

Cash outflows for derivative financial instruments at 31 December	**2018**	2017
Within one year	**1,700**	1,505
1 to 2 years	**1,678**	1,700
2 to 3 years	**2,384**	1,678
3 to 4 years	**2,838**	2,384
4 to 5 years	**2,906**	2,838
5 to 10 years	**11,475**	11,238
Over 10 years	**724**	724
	23,705	22,067

30. 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 29. 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 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. Exchange traded derivatives are typically considered settled through the (normally daily) payment or receipt of variation margin.

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.

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.

30. Derivative financial instruments – continued

				$ million
		2018		2017
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**69**	**(898)**	237	(756)
Oil price derivatives	**2,361**	**(1,849)**	1,637	(1,281)
Natural gas price derivatives	**4,787**	**(3,888)**	3,580	(2,844)
Power price derivatives	**1,240**	**(943)**	885	(693)
Other derivatives	**107**	**—**	115	—
	8,564	**(7,578)**	6,454	(5,574)
Embedded derivatives				
Commodity price contracts	**—**	**—**	—	(16)
Other embedded derivatives	**—**	**(107)**	—	(115)
	—	**(107)**	—	(131)
Cash flow hedges				
Currency forwards, futures and cylinders	**5**	**(14)**	35	(35)
Gas price futures	**2**	**—**	—	—
	7	**(14)**	35	(35)
Fair value hedges				
Currency forwards, futures and swaps	**158**	**(789)**	460	(523)
Interest rate swaps	**262**	**(445)**	193	(306)
	420	**(1,234)**	653	(829)
	8,991	**(8,933)**	7,142	(6,569)
Of which – current	**3,846**	**(3,308)**	3,032	(2,808)
– non-current	**5,145**	**(5,625)**	4,110	(3,761)

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 29.

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
							2018
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**48**	**12**	**9**	**—**	**—**	**—**	**69**
Oil price derivatives	**1,916**	**363**	**53**	**25**	**4**	**—**	**2,361**
Natural gas price derivatives	**1,333**	**708**	**542**	**452**	**352**	**1,400**	**4,787**
Power price derivatives	**540**	**276**	**158**	**79**	**55**	**132**	**1,240**
Other derivatives	**—**	**—**	**—**	**—**	**107**	**—**	**107**
	3,837	**1,359**	**762**	**556**	**518**	**1,532**	**8,564**

							$ million
							2017
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	186	31	8	5	3	4	237
Oil price derivatives	1,280	177	99	66	14	1	1,637
Natural gas price derivatives	1,122	609	428	328	288	805	3,580
Power price derivatives	420	188	81	60	38	98	885
Other derivatives	—	—	—	—	—	115	115
	3,008	1,005	616	459	343	1,023	6,454

30. Derivative financial instruments – continued

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

							$ million
							2018
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**(299)**	**(71)**	**(256)**	**(171)**	**(3)**	**(98)**	**(898)**
Oil price derivatives	**(1,560)**	**(232)**	**(43)**	**(12)**	**(2)**	**—**	**(1,849)**
Natural gas price derivatives	**(1,030)**	**(557)**	**(391)**	**(338)**	**(285)**	**(1,287)**	**(3,888)**
Power price derivatives	**(401)**	**(213)**	**(95)**	**(54)**	**(47)**	**(133)**	**(943)**
	(3,290)	**(1,073)**	**(785)**	**(575)**	**(337)**	**(1,518)**	**(7,578)**

							$ million
							2017
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(92)	(232)	(66)	(188)	(99)	(79)	(756)
Oil price derivatives	(1,120)	(118)	(33)	(4)	(6)	—	(1,281)
Natural gas price derivatives	(973)	(410)	(334)	(224)	(194)	(709)	(2,844)
Power price derivatives	(337)	(134)	(63)	(39)	(29)	(91)	(693)
	(2,522)	(894)	(496)	(455)	(328)	(879)	(5,574)

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
							2018
	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	**111**	**14**	**3**	**—**	**—**	**—**	**128**
Level 2	**5,000**	**1,362**	**504**	**262**	**120**	**72**	**7,320**
Level 3	**491**	**385**	**353**	**331**	**427**	**1,640**	**3,627**
	5,602	**1,761**	**860**	**593**	**547**	**1,712**	**11,075**
Less: netting by counterparty	**(1,765)**	**(402)**	**(98)**	**(37)**	**(29)**	**(180)**	**(2,511)**
	3,837	**1,359**	**762**	**556**	**518**	**1,532**	**8,564**
Fair value of derivative liabilities							
Level 1	**(156)**	**(11)**	**(2)**	**(2)**	**—**	**—**	**(171)**
Level 2	**(4,562)**	**(1,161)**	**(576)**	**(308)**	**(67)**	**(163)**	**(6,837)**
Level 3	**(337)**	**(303)**	**(305)**	**(302)**	**(299)**	**(1,535)**	**(3,081)**
	(5,055)	**(1,475)**	**(883)**	**(612)**	**(366)**	**(1,698)**	**(10,089)**
Less: netting by counterparty	**1,765**	**402**	**98**	**37**	**29**	**180**	**2,511**
	(3,290)	**(1,073)**	**(785)**	**(575)**	**(337)**	**(1,518)**	**(7,578)**
Net fair value	**547**	**286**	**(23)**	**(19)**	**181**	**14**	**986**

							$ million
							2017
	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 2	3,663	1,003	438	244	140	135	5,623
Level 3	386	258	231	226	211	899	2,211
	4,049	1,261	669	470	351	1,034	7,834
Less: netting by counterparty	(1,041)	(256)	(53)	(11)	(8)	(11)	(1,380)
	3,008	1,005	616	459	343	1,023	6,454
Fair value of derivative liabilities							
Level 2	(3,338)	(953)	(358)	(289)	(163)	(166)	(5,267)
Level 3	(225)	(197)	(191)	(177)	(173)	(724)	(1,687)
	(3,563)	(1,150)	(549)	(466)	(336)	(890)	(6,954)
Less: netting by counterparty	1,041	256	53	11	8	11	1,380
	(2,522)	(894)	(496)	(455)	(328)	(879)	(5,574)
Net fair value	486	111	120	4	15	144	880

30. 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**
Fair value contracts at 1 January 2018	**67**	**65**	**(226)**	**115**	**21**
Gains (losses) recognized in the income statement	**58**	**(26)**	**209**	**(8)**	**233**
Settlements	**(107)**	**(32)**	**(97)**	**—**	**(236)**
Transfers out of level 3	**5**	**(20)**	**(34)**	**—**	**(49)**
Net fair value of contracts at 31 December 2018	**23**	**(13)**	**(148)**	**107**	**(31)**
Deferred day-one gains (losses)					**577**
Derivative asset (liability)					**546**

					$ million
	Oil price	Natural gas price	Power price	Other	Total
Fair value contracts at 1 January 2017	68	145	(147)	231	297
Gains (losses) recognized in the income statement	76	161	61	15	313
Settlements	(68)	(35)	(113)	(131)	(347)
Transfers out of level 3	(9)	(206)	(27)	—	(242)
Net fair value of contracts at 31 December 2017	67	65	(226)	115	21
Deferred day-one gains (losses)					503
Derivative asset (liability)					524

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2018 was a $123-million gain (2017 $234-million gain related to derivatives still held at 31 December 2017).

Derivative gains and losses

The group enters into derivative contracts including futures, options, swaps and certain forward sales and forward purchases contracts, relating 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. These gains and losses are included within sales and other operating revenues in the income statement. Also included within this line item 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 $2,504 million (2017 $1,983 million net gain and 2016 $1,435 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 amounts for actual gains and losses relating to these derivative contracts and all related items therefore differ significantly from the amounts disclosed above.

The group also enters into derivative contracts including futures, options, swaps and certain forward sales and forward purchase contracts primarily relating to foreign currency risk management activities. Gains and losses on these contracts are included within production and manufacturing expenses in the income statement. The change in the unrealized value of these contracts was a net loss of $351 million (2017 $1,420 million net gain and 2016 $154 million net loss), however the gains and losses in each year are largely offset by opposing net foreign exchange differences on retranslation of the associated non-US dollar debt. The net amounts for actual gains and losses relating to these derivative contracts and all related items therefore differ significantly from the amounts disclosed above.

Cash flow hedges

(i) Foreign currency risk of highly probable forecast capital expenditure

At 31 December 2018, the group held currency forwards designated as hedging instruments in cash flow hedge relationships of highly probable forecast non-US dollar capital expenditure. Note 29 outlines the group's approach to foreign currency exchange risk management. When the highly probable forecast capital expenditure designated as a hedged item occurs, a non-financial asset is recognized and is presented within the fixed asset section of the balance sheet.

The group claims hedge accounting only for the spot value of the currency exposure in line with the strategy to fix the volatility in the spot exchange rate element. The fair value on the instrument attributable to forward points is taken immediately to the income statement.

The group applies hedge accounting where there is an economic relationship between the hedged item and hedging instrument. The existence of an economic relationship is determined at inception and prospectively by comparing the critical terms of the hedging instrument and those of the hedged item. The group enters into hedging derivatives that match the currency and notional of the hedged items on a 1:1 hedge ratio basis. The hedge ratio is determined by comparing the notional amount of the derivative with the notional designated on the forecast transaction. The group determines the extent to which it hedges highly probable forecast capital expenditures on a project by project basis.

The group has identified the following sources of ineffectiveness, which are not expected to be material:

- counterparty's credit risk, the group mitigates counterparty credit risk by entering into derivative transactions with high credit quality counterparties; and
- differences in settlement timing between the derivative and hedged items. The latter impacts the discount factor used in the calculation of the hedge ineffectiveness. The group mitigates differences in timing between the derivatives and hedged items by applying a rolling strategy and by hedging currency pairs from stable economies (i.e. sterling/US dollar, Euro/US dollar, Norwegian krone/US dollar, Korean won/US dollar). The group's cash flow hedge designations are highly effective as the sources of ineffectiveness identified are expected to result in minimal hedge ineffectiveness.

The group has not designated any net positions as hedged items in cash flow hedges of foreign currency risk.

30. Derivative financial instruments – continued

(ii) Commodity price risk of highly probable forecast sales

At 31 December 2018, the group held Henry Hub NYMEX futures designated as hedging instruments in cash flow hedge relationships of certain highly probable forecast future sales.

The group is exposed to the variability in the gas price, but only applies hedge accounting to the risk of Henry Hub price movements for a percentage of future gas sales from its BPX Energy business (previously known as US Lower 48 business). Hedge accounting may be applied to such sales for up to the following two calendar years.

The group applies hedge accounting in relation to these highly probable future sales where there is an economic relationship between the hedged item and hedging instrument. The existence of an economic relationship is determined at inception and prospectively by comparing the critical terms of the hedging instrument and those of the hedged item. The group enters into hedging derivatives that match the notional amounts of the hedged items on a 1:1 hedge ratio basis. The hedge ratio is determined by comparing the notional amount of the derivative with the notional amount designated on the forecast transaction.

The hedge is expected to be highly effective due to the price index of the hedging instruments matching the price index of the hedged item and the derivative assets or liabilities recognized in respect of exchange-traded instruments reflect the impact of daily margin payments and receipts.

The group has not designated any net positions as hedged items in cash flow hedges of commodity price risk.

The table below summarizes the change in the fair value of hedging instruments and the hedged item used to calculate ineffectiveness in the period.

			$ million
At 31 December 2018	Change in fair value of hedging instrument used to calculate ineffectiveness	Change in fair value of hedged item used to calculate ineffectiveness	Hedge ineffectiveness recognized in profit or (loss)
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	(5)	5	—
Commodity price risk			
Highly probable forecast sales	(126)	126	—

The table below summarizes the carrying amount and nominal amount of the derivatives designated as hedging instruments in cash flow hedge relationships at 31 December 2018.

	Carrying amount of hedging instrument		Nominal amounts of hedging instruments	
	Assets	Liabilities		
At 31 December 2018	$ million	$ million	$ million	mmBtu
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	5	(14)	386	
Commodity price risk				
Highly probable forecast sales	2	—		145

All hedging instruments are presented within derivative financial instruments on the group balance sheet.

Of the nominal amount of hedging instruments relating to highly probable forecast capital expenditure $304 million matures in 2019 and $82 million matures in 2020. All of the hedging instruments relating to highly probable forecast sales mature in 2019.

The table below summarizes the weighted average exchange rates and the weighted average sales price in relation to the derivatives designated as hedging instruments in cash flow hedge relationships at 31 December 2018.

	Weighted average price/rate	
At 31 December 2018	Forecast capital expenditure	Forecast sales
Sterling/US dollar	1.34	
Euro/US dollar	1.14	
Australian dollar/US dollar	0.72	
Norwegian krone/US dollar	8.67	
Korean won/US dollar	1,107.90	
Henry Hub $/mmBtu		2.86

30. Derivative financial instruments – continued

Fair value hedges

At 31 December 2018, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk and foreign currency risk arising from group fixed rate debt issuances. The interest rate swaps are used to convert US dollar denominated fixed rate borrowings into floating rate debt. The cross-currency interest rate swaps are used to convert sterling, euro, Swiss franc, Australian dollar, Canadian dollar and Norwegian krone denominated fixed rate borrowings into US dollar floating rate debt. The group manages all risks derived from debt issuance, such as credit risk, however, the group applies hedge accounting only to certain components of interest rate and foreign currency risk in order to minimize hedge ineffectiveness. Note 29 outlines the group's approach to interest rate and foreign currency exchange risk management.

The interest rate and foreign currency exposures are identified and hedged on an instrument-by-instrument basis. For interest rate exposures, the group designates as a fair value hedge the benchmark interest rate component only. This is an observable and reliably measurable component of interest rate risk. For foreign currency exposures, the group excludes from the designation the foreign currency basis spread component implicit in the cross-currency interest rate swaps. This is separately calculated at hedge designation, is recognized in other comprehensive income over the life of the hedge and amortized to the income statement on a straight-line basis, in accordance with the group's policy on costs of hedging.

The group applies hedge accounting where there is an economic relationship between the hedged item and the hedging instrument. The existence of an economic relationship is determined initially by comparing the critical terms of the hedging instrument and those of the hedged item and it is prospectively assessed using linear regression analysis. The group issues fixed rate debt and enters into interest rate and cross-currency interest rate swaps with critical terms that match those of the debt and on a 1:1 hedge ratio basis. The hedge ratio is determined by comparing the notional amount of the derivative with the notional amount of the debt. The hedge relationship is designated for the full term and notional value of the debt. Both the hedging instrument and the hedged item are expected to be held to maturity.

The group has identified the following sources of ineffectiveness, which are not expected to be material:

- derivative counterparty's credit risk which is not offset by the hedged item. This risk is mitigated by entering into derivative transactions only with high credit quality counterparties; and
- sensitivity to interest rate between the hedged item and the derivatives. This is driven by differences in payment frequencies between the instrument and the bond.

The table below summarizes the change in the fair value of hedging instruments and the hedged item used to calculate ineffectiveness in the period.

At 31 December 2018	Change in fair value of hedging instrument used to calculate ineffectiveness	Change in fair value of hedged item used to calculate ineffectiveness	Hedge ineffectiveness recognized in profit or (loss)
			$ million
Fair value hedges			
Interest rate risk on finance debt	**(70)**	**69**	**(1)**
Interest rate and foreign currency risk on finance debt	**812**	**(809)**	**3**

The table below summarizes the carrying amount of the derivatives designated as hedging instruments in fair value hedge relationships at 31 December 2018.

At 31 December 2018	Carrying amount of hedging instrument		Nominal amounts of hedging instruments
	Assets	Liabilities	$ million
Fair value hedges			
Interest rate risk on finance debt	**262**	**(445)**	**24,513**
Interest rate and foreign currency risk on finance debt	**158**	**(789)**	**16,580**

All hedging instruments are presented within derivative financial instruments on the group balance sheet. Ineffectiveness arising on fair value hedges is included within the production and manufacturing expenses section of the income statement.

The table below summarizes the profile by tenor of the nominal amount of the derivatives designated as hedging instruments in fair value hedge relationships at 31 December 2018. The weighted average floating interest rate of these interest rate swaps and cross-currency interest rate swaps was 3.04% and 4.07% respectively.

At 31 December 2018	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	5-10 years	Over 10 years	Total ($ million)
Fair value hedges								
Interest rate risk on finance debt	**2,694**	**2,324**	**2,597**	**4,923**	**1,700**	**10,275**	**—**	**24,513**
Interest rate and foreign currency risk on finance debt	**—**	**1,245**	**1,167**	**707**	**2,921**	**10,254**	**286**	**16,580**

30. Derivative financial instruments – continued

The table below summarizes the carrying amount, and the accumulated fair value adjustments included within the carrying amount, of the hedged items designated in fair value hedge relationships at 31 December 2018.

					$ million
	Carrying amount of hedged item		Accumulated fair value adjustment included in the carrying amount of hedged items		
At 31 December 2018	Assets	Liabilities	Assets	Liabilities	Discontinued hedges
Fair value hedges					
Interest rate risk on finance debt	**—**	**(24,747)**	**175**	**—**	**(360)**
Interest rate and foreign currency risk on finance debt	**—**	**(16,883)**	**—**	**(62)**	**—**

The hedged item for all fair value hedges is presented within finance debt on the group balance sheet.

Movement in reserves related to hedge accounting

The table below provides a reconciliation of the cash flow hedge and costs of hedging reserves on a pre-tax basis by risk category. The signage convention of this table is consistent with that presented in Note 32.

					$ million
	Cash flow hedge reserve			Costs of hedging reserve	
	Highly probable forecast capital expenditure	Highly probable forecast sales	Purchase of equity[a]	Interest rate and foreign currency risk on finance debt	Total
At 31 December 2017	**(10)**	**—**	**(651)**	**—**	**(661)**
Adjustment on adoption of IFRS 9	**—**	**—**	**—**	**(37)**	**(37)**
At 1 January 2018	**(10)**	**—**	**(651)**	**(37)**	**(698)**
Recognized in other comprehensive income					
Cash flow hedges marked to market	**(37)**	**(126)**	**—**	**—**	**(163)**
Cash flow hedges reclassified to the income statement- hedged item affected profit or loss	**—**	**120**	**—**	**—**	**120**
Costs of hedging marked to market	**—**	**—**	**—**	**(244)**	**(244)**
Costs of hedging reclassified to the income statement	**—**	**—**	**—**	**58**	**58**
	(37)	**(6)**	**—**	**(186)**	**(229)**
Cash flow hedges transferred to the balance sheet	**26**	**—**	**—**	**—**	**26**
At 31 December 2018	**(21)**	**(6)**	**(651)**	**(223)**	**(901)**

[a] See Note 32 for further information on the cash flow hedge reserve relating to the purchase of equity

Substantially all of the cash flow hedge reserve balances and all of the amounts reclassified into profit or loss during the year relate to continuing hedge relationships. Amounts deferred in the cash flow hedge reserve that have been reclassified to profit or loss are presented in sales and other operating revenues in the income statement.

Costs of hedging relates to the foreign currency basis spreads of hedging instruments used to hedge the group's interest rate and foreign currency risk on debt which is a time-period related item.

31. Called-up share capital

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

	2018		2017		2016	
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	**21,288,193**	**5,322**	21,049,696	5,263	20,108,771	5,028
Issue of new shares for the scrip dividend programme	**195,305**	**49**	289,789	72	548,005	137
Issue of new shares for employee share-based payment plans	**92,168**	**23**	—	—	—	—
Issue of new shares – other[b]	**—**	**—**	—	—	392,920	98
Repurchase of ordinary share capital	**(50,202)**	**(13)**	(51,292)	(13)	—	—
At 31 December	**21,525,464**	**5,381**	21,288,193	5,322	21,049,696	5,263
		5,402		5,343		5,284

[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] 2016 relates to the issue of new ordinary shares in consideration for a 10% interest in the Abu Dhabi onshore oil concession. See Note 32 for further information.

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.

During 2018 the company repurchased 50 million ordinary shares for a total consideration of $355 million, including transaction costs of $2 million, as part of the share repurchase programme announced on 31 October 2017. All shares purchased were for cancellation. The repurchased shares represented 0.2% of ordinary share capital.

Treasury shares[a]

	2018		2017		2016	
	Shares thousand	**Nominal value $ million**	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,482,072**	**370**	1,614,657	403	1,756,327	439
Purchases for settlement of employee share plans	**757**	**—**	4,423	1	9,631	2
Issue of new shares for employee share-based payment plans	**92,168**	**23**	—	—	—	—
Shares re-issued for employee share-based payment plans	**(148,732)**	**(37)**	(137,008)	(34)	(151,301)	(38)
At 31 December	**1,426,265**	**356**	1,482,072	370	1,614,657	403
Of which – shares held in treasury by BP	**1,264,732**	**316**	1,472,343	368	1,576,411	394
– shares held in ESOP trusts	**161,518**	**40**	9,705	2	21,432	5
– shares held by BP's US share plan administrator[b]	**15**	**—**	24	—	16,814	4

[a] See Note 32 for definition of treasury shares.

[b] Held 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 6.9% (2017 7.5% and 2016 8.6%) of the called-up ordinary share capital of the company.

During 2018, the movement in shares held in treasury by BP represented less than 1.0% (2017 less than 0.5% and 2016 less than 0.8%) of the ordinary share capital of the company.

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32. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 31 December 2017	**5,343**	**12,147**	**1,426**	**27,206**	**46,122**
Adjustment on adoption of IFRS 9, net of tax	—	—	—	—	—
At 1 January 2018	**5,343**	**12,147**	**1,426**	**27,206**	**46,122**
Profit (loss) for the year	—	—	—	—	—
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications)	—	—	—	—	—
Cash flow hedges and costs of hedging (including reclassifications)	—	—	—	—	—
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	—	—	—	—	—
Cash flow hedges that will subsequently be transferred to the balance sheet	—	—	—	—	—
Total comprehensive income	—	—	—	—	—
Dividends	**49**	**(49)**	—	—	—
Cash flow hedges transferred to the balance sheet, net of tax	—	—	—	—	—
Repurchases of ordinary share capital	**(13)**	—	**13**	—	—
Share-based payments, net of tax[b]	**23**	**207**	—	—	**230**
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
Transactions involving non-controlling interests, net of tax	—	—	—	—	—
At 31 December 2018	**5,402**	**12,305**	**1,439**	**27,206**	**46,352**

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2017	5,284	12,219	1,413	27,206	46,122
Profit (loss) for the year	—	—	—	—	—
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications)	—	—	—	—	—
Available-for-sale investments (including reclassifications)	—	—	—	—	—
Cash flow hedges (including reclassifications)	—	—	—	—	—
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	—	—	—	—	—
Total comprehensive income	—	—	—	—	—
Dividends	72	(72)	—	—	—
Repurchases of ordinary share capital	(13)	—	13	—	—
Share-based payments, net of tax[b]	—	—	—	—	—
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
Transactions involving non-controlling interests, net of tax[c]	—	—	—	—	—
At 31 December 2017	5,343	12,147	1,426	27,206	46,122

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2016	5,049	10,234	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 reclassifications)[a]	—	—	—	—	—
Available-for-sale investments (including reclassifications)	—	—	—	—	—
Cash flow hedges (including reclassifications)	—	—	—	—	—
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	—	—	—	—	—
Total comprehensive income	—	—	—	—	—
Dividends	137	(137)	—	—	—
Share-based payments, net of tax[b d]	98	2,122	—	—	2,220
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
Transactions involving non-controlling interests, net of tax	—	—	—	—	—
At 31 December 2016	5,284	12,219	1,413	27,206	46,122

[a] Principally foreign exchange effects relating to the Russian rouble.

[b] Movements in treasury shares relate to employee share-based payment plans.

32. Capital and reserves – continued

$ million

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Costs of hedging	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(16,958)	**(5,156)**	**17**	**(760)**	**—**	**(743)**	**75,226**	**98,491**	**1,913**	**100,404**
—	**—**	**(17)**	**—**	**(37)**	**(54)**	**(126)**	**(180)**	**—**	**(180)**
(16,958)	**(5,156)**	**—**	**(760)**	**(37)**	**(797)**	**75,100**	**98,311**	**1,913**	**100,224**
—	**—**	**—**	**—**	**—**	**—**	**9,383**	**9,383**	**195**	**9,578**
—	**(3,746)**	**—**	**—**	**—**	**—**	**—**	**(3,746)**	**(41)**	**(3,787)**
—	**—**	**—**	**(6)**	**(173)**	**(179)**	**—**	**(179)**	**—**	**(179)**
—	**—**	**—**	**—**	**—**	**—**	**417**	**417**	**—**	**417**
—	**—**	**—**	**—**	**—**	**—**	**7**	**7**	**—**	**7**
—	**—**	**—**	**—**	**—**	**—**	**1,599**	**1,599**	**—**	**1,599**
—	**—**	**—**	**(37)**	**—**	**(37)**	**—**	**(37)**	**—**	**(37)**
—	**(3,746)**	**—**	**(43)**	**(173)**	**(216)**	**11,406**	**7,444**	**154**	**7,598**
—	**—**	**—**	**—**	**—**	**—**	**(6,699)**	**(6,699)**	**(170)**	**(6,869)**
—	**—**	**—**	**26**	**—**	**26**	**—**	**26**	**—**	**26**
—	**—**	**—**	**—**	**—**	**—**	**(355)**	**(355)**	**—**	**(355)**
1,191	**—**	**—**	**—**	**—**	**—**	**(718)**	**703**	**—**	**703**
—	**—**	**—**	**—**	**—**	**—**	**14**	**14**	**—**	**14**
—	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**207**	**207**
(15,767)	**(8,902)**	**—**	**(777)**	**(210)**	**(987)**	**78,748**	**99,444**	**2,104**	**101,548**

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Costs of hedging	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(18,443)	(6,878)	3	(1,156)	—	(1,153)	75,638	95,286	1,557	96,843
—	—	—	—	—	—	3,389	3,389	79	3,468
—	1,722	—	—	—	—	(3)	1,719	52	1,771
—	—	14	—	—	14	—	14	—	14
—	—	—	396	—	396	—	396	—	396
—	—	—	—	—	—	564	564	—	564
—	—	—	—	—	—	(72)	(72)	—	(72)
—	—	—	—	—	—	2,343	2,343	—	2,343
—	1,722	14	396	—	410	6,221	8,353	131	8,484
—	—	—	—	—	—	(6,153)	(6,153)	(141)	(6,294)
—	—	—	—	—	—	(343)	(343)	—	(343)
1,485	—	—	—	—	—	(798)	687	—	687
—	—	—	—	—	—	215	215	—	215
—	—	—	—	—	—	446	446	366	812
(16,958)	(5,156)	17	(760)	—	(743)	75,226	98,491	1,913	100,404

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Costs of hedging	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(19,964)	(7,267)	2	(825)	—	(823)	81,368	97,216	1,171	98,387
—	—	—	—	—	—	115	115	57	172
—	389	—	—	—	—	—	389	(27)	362
—	—	1	—	—	1	—	1	—	1
—	—	—	(331)	—	(331)	—	(331)	—	(331)
—	—	—	—	—	—	833	833	—	833
—	—	—	—	—	—	(96)	(96)	—	(96)
—	—	—	—	—	—	(1,757)	(1,757)	—	(1,757)
—	389	1	(331)	—	(330)	(905)	(846)	30	(816)
—	—	—	—	—	—	(4,611)	(4,611)	(107)	(4,718)
1,521	—	—	—	—	—	(750)	2,991	—	2,991
—	—	—	—	—	—	106	106	—	106
—	—	—	—	—	—	430	430	463	893
(18,443)	(6,878)	3	(1,156)	—	(1,153)	75,638	95,286	1,557	96,843

[c] Principally relates to the initial public offering of common units in BP Midstream Partners LP for which net proceeds of $811 million were received.

[d] Includes ordinary shares issued to the government of Abu Dhabi in consideration for a 10% interest in the Abu Dhabi onshore oil concession. The share-based payment transaction was valued at the fair value of the interest in the assets, with reference to a market transaction for an identical interest.

32. 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) and BP's US share plan administrator 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 reclassified to the income statement.

Available-for-sale investments
This reserve recorded the changes in fair value of investments classified as available-for-sale under IAS 39 except for impairment losses, foreign exchange gains or losses, or changes arising from revised estimates of future cash flows. On adoption of IFRS 9 the balance in this reserve was transferred to the profit and loss account reserve. Under the new standard the group recognizes fair value gains and losses on these investments in profit or loss.

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. It includes $651 million relating to the acquisition of an 18.5% interest in Rosneft in 2013 which will only be reclassified to the income statement if the investment in Rosneft is either sold or impaired. For further information on the accounting for cash flow hedges see Note 1 - Derivative financial instruments and hedging activities.

Costs of hedging
This reserve records the change in fair value of the foreign currency basis spread of financial instruments to which cost of hedge accounting has been applied. The accumulated amount relates to time-period related hedged items and is amortized to profit or loss over the term of the hedging relationship.

Prior to the group's adoption of IFRS 9 changes in the fair value of such foreign currency basis spreads were recognized in profit or loss. On adoption of the new standard a transfer from the profit and loss account reserve to the costs of hedging reserve was made in order to reflect the opening reserves position for relevant hedging instruments existing on transition. For further information on the accounting for costs of hedging 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.

32. 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
			2018
	Pre-tax	**Tax**	**Net of tax**
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	**(3,771)**	**(16)**	**(3,787)**
Cash flow hedges (including reclassifications)	**(6)**	**—**	**(6)**
Costs of hedging (including reclassifications)	**(186)**	**13**	**(173)**
Share of items relating to equity-accounted entities, net of tax	**417**	**—**	**417**
Other	**—**	**7**	**7**
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	**2,317**	**(718)**	**1,599**
Cash flow hedges that will subsequently be transferred to the balance sheet	**(37)**	**—**	**(37)**
Other comprehensive income	**(1,266)**	**(714)**	**(1,980)**

			$ million
			2017
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	1,866	(95)	1,771
Available-for-sale investments (including reclassifications)	14	—	14
Cash flow hedges (including reclassifications)	425	(29)	396
Share of items relating to equity-accounted entities, net of tax	564	—	564
Other	—	(72)	(72)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	3,646	(1,303)	2,343
Other comprehensive income	6,515	(1,499)	5,016

			$ million
			2016
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	284	78	362
Available-for-sale investments (including reclassifications)	1	—	1
Cash flow hedges (including reclassifications)	(362)	31	(331)
Share of items relating to equity-accounted entities, net of tax	833	—	833
Other	—	(96)	(96)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	(2,496)	739	(1,757)
Other comprehensive income	(1,740)	752	(988)

33. Contingent liabilities

Contingent liabilities related to the Gulf of Mexico oil spill

See Note 2 for information on contingent liabilities related to the Gulf of Mexico oil spill.

Contingent liabilities not related to the Gulf of Mexico oil spill

There were contingent liabilities at 31 December 2018 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 on financial guarantees is included in Note 29.

In the normal course of the group's business, legal and regulatory 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 health, safety and 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 and regulatory proceedings on the group's results of operations, liquidity or financial position will not be material.

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 including the tax deductibility of certain intercompany charges. The resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete and the amounts could be significant and could be material to the group's results of operations, financial position or liquidity. 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.

33. Contingent liabilities – continued

The group is subject to numerous national and local health, safety and 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, commodities extraction sites, 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 impact on the group's results of operations, 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. While the amounts associated with decommissioning provisions reverting to the group could be significant and could be material, BP is not currently aware of any such cases that have a greater than remote chance of reverting to the group. Furthermore, as described in Provisions and contingencies 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.

See also Legal proceedings on pages 296-298.

34. Remuneration of senior management and non-executive directors

Remuneration of directors

			$ million
	2018	2017	2016
Total for all directors			
Emoluments	**8**	9	10
Amounts received under incentive schemes[a]	**16**	9	14
Total	**24**	18	24

[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 2018 one executive director participated in a UK final salary pension plan in respect of service prior to 1 April 2011. During 2018, one executive director participated in retirement savings plans established for US employees and in a US defined benefit pension plan in respect of service prior to 1 September 2016.

Further information

Full details of individual directors' remuneration are given in the Directors' remuneration report on page 87. See also Related-party transactions on page 300.

Remuneration of directors and senior management

			$ million
	2018	2017	2016
Total for all senior management and non-executive directors			
Short-term employee benefits	**25**	29	28
Pensions and other post-retirement benefits	**2**	2	3
Share-based payments	**32**	29	39
Total	**59**	60	70

Senior management comprises members of the executive team, see pages 63-65 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. Short term employee benefits includes compensation for loss of office of $nil in 2018 (2017 $nil and 2016 $2.2 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'.

35. Employee costs and numbers

Employee costs	2018	2017	2016
			$ million
Wages and salaries[a]	**7,931**	7,572	8,456
Social security costs	**743**	711	760
Share-based payments[b]	**669**	624	764
Pension and other post-retirement benefit costs	**1,154**	1,296	1,253
	10,497	10,203	11,233

Average number of employees[c]	US	Non-US	2018 Total	US	Non-US	2017 Total	US	Non-US	2016 Total
Upstream	**5,900**	**11,500**	**17,400**	6,200	12,200	18,400	6,700	13,500	20,200
Downstream[d e]	**6,000**	**36,300**	**42,300**	6,100	35,900	42,000	6,600	36,600	43,200
Other businesses and corporate[e f]	**1,900**	**12,100**	**14,000**	1,900	12,400	14,300	1,900	12,100	14,000
	13,800	**59,900**	**73,700**	14,200	60,500	74,700	15,200	62,200	77,400

[a] Includes termination costs of $493 million (2017 $189 million and 2016 $545 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 17,100 (2017 16,500 and 2016 15,800) service station staff.

[e] Around 800 centralized function employees were reallocated from Upstream and Downstream to Other businesses and corporate during 2016.

[f] Includes 4,000 (2017 4,700 and 2016 4,900) agricultural, operational and seasonal workers in Brazil.

36. Auditor's remuneration

Fees	2018	2017	2016
			$ million
The audit of the company annual accounts[a]	**25**	26	25
The audit of accounts of subsidiaries of the company	**10**	11	12
Total audit	**35**	37	37
Audit-related assurance services[b]	**4**	7	7
Total audit and audit-related assurance services	**39**	44	44
Taxation compliance services	**—**	—	1
Non-audit and other assurance services	**2**	3	1
Total non-audit or non-audit-related assurance services	**2**	3	2
Services relating to BP pension plans	**1**	—	1
	42	47	47

[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 audit of internal control over financial reporting and non-statutory audit services.

With effect from 2018, following a competitive tender process, Deloitte LLP (Deloitte) was appointed as auditor of the Company, replacing Ernst & Young LLP (EY). In the table above, auditor's remuneration for services provided during the year ended 31 December 2018 thus relates to Deloitte and for the years ended 31 December 2017 and 31 December 2016 to EY.

In addition to the amounts shown in the table above, in 2018 $0.75 million of additional fees were paid to EY in respect of their audit for 2017. 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 Deloitte to render audit and certain assurance and other services. The audit fees payable to Deloitte were considered as part of the audit tender process in 2016 and challenged by the audit committee through comparison with the audit pricing proposals of the other bidding firms, before being approved. Deloitte performed further assurance services that were not prohibited by regulatory or other professional requirements and were pre-approved by the Committee. Deloitte is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit-related or assurance nature.

Under SEC regulations, the remuneration of the auditor of $42 million (2017 $47 million and 2016 $47 million) is required to be presented as follows: audit $35 million (2017 $37 million and 2016 $37 million); other audit-related $4 million (2017 $7 million and 2016 $7 million); tax $nil (2017 $nil and 2016 $1 million); and all other fees $3 million (2017 $3 million and 2016 $2 million).

37. Subsidiaries, joint arrangements and associates

The more important subsidiaries and associates of the group at 31 December 2018 and the group percentage of ordinary share capital (to nearest whole number) are set out below. There are no individually significant incorporated joint arrangements. The group's share of the assets and liabilities of the more important unincorporated joint arrangements are held by subsidiaries listed in the table below. Those subsidiaries 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 14 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
Angola			
BP Exploration (Angola)	100	England & Wales	Exploration and production
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	Germany	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
BP America	100	US	
BP America Production Company	100	US	
BP Company North America	100	US	
BP Corporation North America	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 Oil Company	19.75	Russia	Integrated oil operations

38. 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
					2018
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,315	—	298,620	(4,179)	298,756
Earnings from joint ventures- after interest and tax	—	—	897	—	897
Earnings from associates- after interest and tax	—	—	2,856	—	2,856
Equity-accounted income of subsidiaries- after interest and tax	—	10,942	—	(10,942)	—
Interest and other income	42	373	2,081	(1,723)	773
Gains on sale of businesses and fixed assets	—	—	456	—	456
Total revenues and other income	4,357	11,315	304,910	(16,844)	303,738
Purchases	1,507	—	232,550	(4,179)	229,878
Production and manufacturing expenses	1,015	—	21,990	—	23,005
Production and similar taxes	282	—	1,254	—	1,536
Depreciation, depletion and amortization	377	—	15,080	—	15,457
Impairment and losses on sale of businesses and fixed assets	66	—	794	—	860
Exploration expense	—	—	1,445	—	1,445
Distribution and administration expenses	22	642	11,673	(158)	12,179
Profit (loss) before interest and taxation	1,088	10,673	20,124	(12,507)	19,378
Finance costs	8	1,326	2,759	(1,565)	2,528
Net finance (income) expense relating to pensions and other post-retirement benefits	—	(95)	222	—	127
Profit (loss) before taxation	1,080	9,442	17,143	(10,942)	16,723
Taxation	164	59	6,922	—	7,145
Profit (loss) for the year	916	9,383	10,221	(10,942)	9,578
Attributable to					
BP shareholders	916	9,383	10,026	(10,942)	9,383
Non-controlling interests	—	—	195	—	195
	916	9,383	10,221	(10,942)	9,578

38. Condensed consolidating information on certain US subsidiaries – continued

Statement of comprehensive income

$ million

	Issuer	Guarantor			2018
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	**916**	**9,383**	**10,221**	**(10,942)**	**9,578**
Other comprehensive income					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences	**—**	**(296)**	**(3,475)**	**—**	**(3,771)**
Cash flow hedges (including reclassifications)	**—**	**—**	**(6)**	**—**	**(6)**
Costs of hedging (including reclassifications)	**—**	**—**	**(186)**	**—**	**(186)**
Share of items relating to equity-accounted entities, net of tax	**—**	**—**	**417**	**—**	**417**
Income tax relating to items that may be reclassified	**—**	**—**	**4**	**—**	**4**
	—	**(296)**	**(3,246)**	**—**	**(3,542)**
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	**—**	**1,689**	**628**	**—**	**2,317**
Cash flow hedges that will subsequently be transferred to the balance sheet	**—**	**—**	**(37)**	**—**	**(37)**
Income tax relating to items that will not be reclassified	**—**	**(511)**	**(207)**	**—**	**(718)**
	—	**1,178**	**384**	**—**	**1,562**
Other comprehensive income	**—**	**882**	**(2,862)**	**—**	**(1,980)**
Equity-accounted other comprehensive income of subsidiaries	**—**	**(2,821)**	**—**	**2,821**	**—**
Total comprehensive income	**916**	**7,444**	**7,359**	**(8,121)**	**7,598**
Attributable to					
BP shareholders	**916**	**7,444**	**7,205**	**(8,121)**	**7,444**
Non-controlling interests	**—**	**—**	**154**	**—**	**154**
	916	**7,444**	**7,359**	**(8,121)**	**7,598**

Income statement continued

$ million

	Issuer	Guarantor			2017
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	3,264	—	240,177	(3,233)	240,208
Earnings from joint ventures- after interest and tax	—	—	1,177	—	1,177
Earnings from associates- after interest and tax	—	—	1,330	—	1,330
Equity-accounted income of subsidiaries- after interest and tax	—	4,436	—	(4,436)	—
Interest and other income	11	369	1,470	(1,193)	657
Gains on sale of businesses and fixed assets	71	9	1,139	(9)	1,210
Total revenues and other income	3,346	4,814	245,293	(8,871)	244,582
Purchases	1,010	—	181,939	(3,233)	179,716
Production and manufacturing expenses	1,156	—	23,073	—	24,229
Production and similar taxes[a]	(18)	—	1,793	—	1,775
Depreciation, depletion and amortization	735	—	14,849	—	15,584
Impairment and losses on sale of businesses and fixed assets	—	—	1,216	—	1,216
Exploration expense	—	—	2,080	—	2,080
Distribution and administration expenses	19	616	10,022	(149)	10,508
Profit (loss) before interest and taxation	444	4,198	10,321	(5,489)	9,474
Finance costs	6	826	2,286	(1,044)	2,074
Net finance (income) expense relating to pensions and other post-retirement benefits	—	(15)	235	—	220
Profit (loss) before taxation	438	3,387	7,800	(4,445)	7,180
Taxation	(392)	(11)	4,115	—	3,712
Profit (loss) for the year	830	3,398	3,685	(4,445)	3,468
Attributable to					
BP shareholders	830	3,398	3,606	(4,445)	3,389
Non-controlling interests	—	—	79	—	79
	830	3,398	3,685	(4,445)	3,468

[a] Includes revised non-cash provision adjustments; actual cash payments for Production and similar taxes remain in line with prior year.

38. Condensed consolidating information on certain US subsidiaries – continued

Statement of comprehensive income continued

$ million

2017

	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	830	3,398	3,685	(4,445)	3,468
Other comprehensive income					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences	—	166	1,820	—	1,986
Exchange (gains) losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	—	—	(120)	—	(120)
Available-for-sale investments marked to market	—	—	14	—	14
Cash flow hedges marked to market	—	—	197	—	197
Cash flow hedges reclassified to the income statement	—	—	116	—	116
Cash flow hedges reclassified to the balance sheet	—	—	112	—	112
Share of items relating to equity-accounted entities, net of tax	—	—	564	—	564
Income tax relating to items that may be reclassified	—	—	(196)	—	(196)
	—	166	2,507	—	2,673
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	2,984	662	—	3,646
Income tax relating to items that will not be reclassified	—	(1,169)	(134)	—	(1,303)
	—	1,815	528	—	2,343
Other comprehensive income	—	1,981	3,035	—	5,016
Equity-accounted other comprehensive income of subsidiaries	—	2,983	—	(2,983)	—
Total comprehensive income	830	8,362	6,720	(7,428)	8,484
Attributable to					
BP shareholders	830	8,362	6,589	(7,428)	8,353
Non-controlling interests	—	—	131	—	131
	830	8,362	6,720	(7,428)	8,484

Income statement continued

$ million

2016

	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	2,740	—	182,999	(2,731)	183,008
Earnings from joint ventures- after interest and tax	—	—	966	—	966
Earnings from associates- after interest and tax	—	—	994	—	994
Equity-accounted income of subsidiaries- after interest and tax	—	862	—	(862)	—
Interest and other income	94	343	899	(830)	506
Gains on sale of businesses and fixed assets	—	—	1,132	—	1,132
Total revenues and other income	2,834	1,205	186,990	(4,423)	186,606
Purchases	888	—	134,062	(2,731)	132,219
Production and manufacturing expenses	1,171	—	27,906	—	29,077
Production and similar taxes	102	—	581	—	683
Depreciation, depletion and amortization	673	—	13,832	—	14,505
Impairment and losses on sale of businesses and fixed assets	(147)	—	(1,517)	—	(1,664)
Exploration expense	—	—	1,721	—	1,721
Distribution and administration expenses	—	808	9,797	(110)	10,495
Profit (loss) before interest and taxation	147	397	608	(1,582)	(430)
Finance costs	103	311	1,981	(720)	1,675
Net finance (income) expense relating to pensions and other post-retirement benefits	—	(82)	272	—	190
Profit (loss) before taxation	44	168	(1,645)	(862)	(2,295)
Taxation	(41)	53	(2,479)	—	(2,467)
Profit (loss) for the year	85	115	834	(862)	172
Attributable to					
BP shareholders	85	115	777	(862)	115
Non-controlling interests	—	—	57	—	57
	85	115	834	(862)	172

38. Condensed consolidating information on certain US subsidiaries – continued

Statement of comprehensive income continued

					$ million
					2016
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	85	115	834	(862)	172
Other comprehensive income					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences	—	(236)	490	—	254
Exchange (gains) losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	—	—	30	—	30
Available-for-sale investments marked to market	—	—	1	—	1
Cash flow hedges marked to market	—	—	(639)	—	(639)
Cash flow hedges reclassified to the income statement	—	—	196	—	196
Cash flow hedges reclassified to the balance sheet	—	—	81	—	81
Share of items relating to equity-accounted entities, net of tax	—	—	833	—	833
Income tax relating to items that may be reclassified	—	—	13	—	13
	—	(236)	1,005	—	769
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	(2,019)	(477)	—	(2,496)
Income tax relating to items that will not be reclassified	—	750	(11)	—	739
	—	(1,269)	(488)	—	(1,757)
Other comprehensive income	—	(1,505)	517	—	(988)
Equity-accounted other comprehensive income of subsidiaries	—	544	—	(544)	—
Total comprehensive income	85	(846)	1,351	(1,406)	(816)
Attributable to					
BP shareholders	85	(846)	1,321	(1,406)	(846)
Non-controlling interests	—	—	30	—	30
	85	(846)	1,351	(1,406)	(816)

Balance sheet

					$ million
					2018
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	4,445	—	130,816	—	135,261
Goodwill	—	—	12,204	—	12,204
Intangible assets	598	—	16,686	—	17,284
Investments in joint ventures	—	—	8,647	—	8,647
Investments in associates	—	2	17,671	—	17,673
Other investments	—	—	1,341	—	1,341
Subsidiaries- equity-accounted basis	—	166,311	—	(166,311)	—
Fixed assets	5,043	166,313	187,365	(166,311)	192,410
Loans	—	—	32,402	(31,765)	637
Trade and other receivables	—	2,600	1,834	(2,600)	1,834
Derivative financial instruments	—	—	5,145	—	5,145
Prepayments	—	—	1,179	—	1,179
Deferred tax assets	—	—	3,706	—	3,706
Defined benefit pension plan surpluses	—	5,473	482	—	5,955
	5,043	174,386	232,113	(200,676)	210,866
Current assets					
Loans	—	—	326	—	326
Inventories	302	—	17,686	—	17,988
Trade and other receivables	2,536	151	38,931	(17,140)	24,478
Derivative financial instruments	—	—	3,846	—	3,846
Prepayments	7	—	956	—	963
Current tax receivable	—	—	1,019	—	1,019
Other investments	—	—	222	—	222
Cash and cash equivalents	—	13	22,455	—	22,468
	2,845	164	85,441	(17,140)	71,310
Total assets	7,888	174,550	317,554	(217,816)	282,176
Current liabilities					
Trade and other payables	413	14,634	48,358	(17,140)	46,265
Derivative financial instruments	—	—	3,308	—	3,308
Accruals	89	31	4,506	—	4,626
Finance debt	—	—	9,373	—	9,373
Current tax payable	310	—	1,791	—	2,101
Provisions	1	—	2,563	—	2,564
	813	14,665	69,899	(17,140)	68,237
Non-current liabilities					
Other payables	—	31,800	16,395	(34,365)	13,830
Derivative financial instruments	—	—	5,625	—	5,625
Accruals	—	—	575	—	575
Finance debt	—	—	56,426	—	56,426
Deferred tax liabilities	586	1,907	7,319	—	9,812
Provisions	670	—	17,062	—	17,732
Defined benefit pension plan and other post-retirement benefit plan deficits	—	184	8,207	—	8,391
	1,256	33,891	111,609	(34,365)	112,391
Total liabilities	2,069	48,556	181,508	(51,505)	180,628
Net assets	5,819	125,994	136,046	(166,311)	101,548
Equity					
BP shareholders' equity	5,819	125,994	133,942	(166,311)	99,444
Non-controlling interests	—	—	2,104	—	2,104
	5,819	125,994	136,046	(166,311)	101,548

38. Condensed consolidating information on certain US subsidiaries – continued

Balance sheet continued

					$ million
					2017
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	6,973	—	122,498	—	129,471
Goodwill	—	—	11,551	—	11,551
Intangible assets	585	—	17,770	—	18,355
Investments in joint ventures	—	—	7,994	—	7,994
Investments in associates	—	2	16,989	—	16,991
Other investments	—	—	1,245	—	1,245
Subsidiaries- equity-accounted basis	—	161,840	—	(161,840)	—
Fixed assets	7,558	161,842	178,047	(161,840)	185,607
Loans	1	—	32,401	(31,756)	646
Trade and other receivables	—	2,623	1,434	(2,623)	1,434
Derivative financial instruments	—	—	4,110	—	4,110
Prepayments	—	—	1,112	—	1,112
Deferred tax assets	—	—	4,469	—	4,469
Defined benefit pension plan surpluses	—	3,838	331	—	4,169
	7,559	168,303	221,904	(196,219)	201,547
Current assets					
Loans	—	—	190	—	190
Inventories	274	—	18,737	—	19,011
Trade and other receivables	2,206	293	34,991	(12,641)	24,849
Derivative financial instruments	—	—	3,032	—	3,032
Prepayments	2	—	1,412	—	1,414
Current tax receivable	—	—	761	—	761
Other investments	—	—	125	—	125
Cash and cash equivalents	—	10	25,576	—	25,586
	2,482	303	84,824	(12,641)	74,968
Total assets	10,041	168,606	306,728	(208,860)	276,515
Current liabilities					
Trade and other payables[a]	673	10,143	46,034	(12,641)	44,209
Derivative financial instruments	—	—	2,808	—	2,808
Accruals	115	60	4,785	—	4,960
Finance debt	—	—	7,739	—	7,739
Current tax payable	—	—	1,686	—	1,686
Provisions	1	—	3,323	—	3,324
	789	10,203	66,375	(12,641)	64,726
Non-current liabilities					
Other payables[a]	—	31,804	16,464	(34,379)	13,889
Derivative financial instruments	—	—	3,761	—	3,761
Accruals	—	—	505	—	505
Finance debt	—	—	55,491	—	55,491
Deferred tax liabilities	838	1,337	5,807	—	7,982
Provisions	1,222	—	19,398	—	20,620
Defined benefit pension plan and other post-retirement benefit plan deficits	—	221	8,916	—	9,137
	2,060	33,362	110,342	(34,379)	111,385
Total liabilities	2,849	43,565	176,717	(47,020)	176,111
Net assets	7,192	125,041	130,011	(161,840)	100,404
Equity					
BP shareholders' equity	7,192	125,041	128,098	(161,840)	98,491
Non-controlling interests	—	—	1,913	—	1,913
	7,192	125,041	130,011	(161,840)	100,404

[a] For BP plc, an amount of $2,300 million has been reclassified from non-current other payables to current trade and other payables, with consequential amendments to the eliminations and reclassifications column.

38. Condensed consolidating information on certain US subsidiaries – continued

Cash flow statement

	Issuer	Guarantor			$ million 2018
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Operating activities					
Profit (loss) before taxation	1,080	9,442	17,143	(10,942)	16,723
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities					
Exploration expenditure written off	—	—	1,085	—	1,085
Depreciation, depletion and amortization	377	—	15,080	—	15,457
Impairment and (gain) loss on sale of businesses and fixed assets	66	—	338	—	404
Earnings from joint ventures and associates	—	—	(3,753)	—	(3,753)
Dividends received from joint ventures and associates	—	—	1,535	—	1,535
Equity accounted income of subsidiaries- after interest and tax	—	(10,942)	—	10,942	—
Dividends received from subsidiaries	—	3,490	—	(3,490)	—
Interest receivable	(42)	(215)	(1,776)	1,565	(468)
Interest received	42	215	1,656	(1,565)	348
Finance costs	8	1,326	2,759	(1,565)	2,528
Interest paid	(8)	(1,326)	(2,159)	1,565	(1,928)
Net finance expense relating to pensions and other post-retirement benefits	—	(95)	222	—	127
Share-based payments	—	671	19	—	690
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	—	(183)	(203)	—	(386)
Net charge for provisions, less payments	33	—	953	—	986
(Increase) decrease in inventories	(62)	—	734	—	672
(Increase) decrease in other current and non-current assets	(72)	165	(951)	(2,000)	(2,858)
Increase (decrease) in other current and non-current liabilities	(491)	4,509	(6,595)	—	(2,577)
Income taxes paid	(133)	—	(5,579)	—	(5,712)
Net cash provided by (used in) operating activities	798	7,057	20,508	(5,490)	22,873
Investing activities					
Expenditure on property, plant and equipment, intangible and other assets	(273)	—	(16,434)	—	(16,707)
Acquisitions, net of cash acquired	—	—	(6,986)	—	(6,986)
Investment in joint ventures	—	—	(382)	—	(382)
Investment in associates	—	—	(1,013)	—	(1,013)
Total cash capital expenditure	(273)	—	(24,815)	—	(25,088)
Proceeds from disposals of fixed assets	—	—	940	—	940
Proceeds from disposals of businesses, net of cash disposed	1,475	—	436	—	1,911
Proceeds from loan repayments	—	—	666	—	666
Net cash provided by (used in) investing activities	1,202	—	(22,773)	—	(21,571)
Financing activities					
Repurchase of shares	—	(355)	—	—	(355)
Proceeds from long-term financing	—	—	9,038	—	9,038
Repayments of long-term financing	—	—	(7,210)	—	(7,210)
Net increase (decrease) in short-term debt	—	—	1,317	—	1,317
Dividends paid					
BP shareholders	(2,000)	(6,699)	(3,490)	5,490	(6,699)
Non-controlling interests	—	—	(170)	—	(170)
Net cash provided by (used in) financing activities	(2,000)	(7,054)	(515)	5,490	(4,079)
Currency translation differences relating to cash and cash equivalents	—	—	(330)	—	(330)
Increase (decrease) in cash and cash equivalents	—	3	(3,110)	—	(3,107)
Cash and cash equivalents at beginning of year	—	10	25,565	—	25,575
Cash and cash equivalents at end of year	—	13	22,455	—	22,468

38. Condensed consolidating information on certain US subsidiaries – continued

Cash flow statement continued

	Issuer	Guarantor			$ million 2017
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Operating activities					
Profit (loss) before taxation	438	3,387	7,800	(4,445)	7,180
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities					
Exploration expenditure written off	—	—	1,603	—	1,603
Depreciation, depletion and amortization	735	—	14,849	—	15,584
Impairment and (gain) loss on sale of businesses and fixed assets	(71)	(9)	77	9	6
Earnings from joint ventures and associates	—	—	(2,507)	—	(2,507)
Dividends received from joint ventures and associates	—	—	1,253	—	1,253
Equity accounted income of subsidiaries- after interest and tax	—	(4,436)	—	4,436	—
Dividends received from subsidiaries	—	3,183	—	(3,183)	—
Interest receivable	(11)	(220)	(1,117)	1,044	(304)
Interest received	11	220	1,188	(1,044)	375
Finance costs	6	826	2,286	(1,044)	2,074
Interest paid	(6)	(826)	(1,784)	1,044	(1,572)
Net finance expense relating to pensions and other post-retirement benefits	—	(15)	235	—	220
Share-based payments	—	595	66	—	661
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	—	(145)	(249)	—	(394)
Net charge for provisions, less payments	(128)	—	2,234	—	2,106
(Increase) decrease in inventories	(25)	—	(823)	—	(848)
(Increase) decrease in other current and non-current assets	108	522	(5,478)	—	(4,848)
Increase (decrease) in other current and non-current liabilities	(830)	3,374	(200)	—	2,344
Income taxes paid	—	—	(4,002)	—	(4,002)
Net cash provided by operating activities	227	6,456	15,431	(3,183)	18,931
Investing activities					
Expenditure on property, plant and equipment, intangible and other assets	(321)	—	(16,241)	—	(16,562)
Acquisitions, net of cash acquired	—	—	(327)	—	(327)
Investment in joint ventures	—	—	(50)	—	(50)
Investment in associates	—	—	(901)	—	(901)
Total cash capital expenditure	(321)	—	(17,519)	—	(17,840)
Proceeds from disposals of fixed assets	94	—	2,842	—	2,936
Proceeds from disposals of businesses, net of cash disposed	—	—	478	—	478
Proceeds from loan repayments	—	—	349	—	349
Net cash provided by (used in) investing activities	(227)	—	(13,850)	—	(14,077)
Financing activities					
Net issue (repurchase) of shares	—	(343)	—	—	(343)
Proceeds from long-term financing	—	—	8,712	—	8,712
Repayments of long-term financing	—	—	(6,276)	—	(6,276)
Net increase (decrease) in short-term debt	—	—	(158)	—	(158)
Net increase (decrease) in non-controlling interests	—	—	1,063	—	1,063
Dividends paid					
BP shareholders	—	(6,153)	(3,183)	3,183	(6,153)
Non-controlling interests	—	—	(141)	—	(141)
Net cash provided by (used in) financing activities	—	(6,496)	17	3,183	(3,296)
Currency translation differences relating to cash and cash equivalents	—	—	544	—	544
Increase (decrease) in cash and cash equivalents	—	(40)	2,142	—	2,102
Cash and cash equivalents at beginning of year	—	50	23,434	—	23,484
Cash and cash equivalents at end of year	—	10	25,576	—	25,586

38. Condensed consolidating information on certain US subsidiaries – continued

Cash flow statement continued

	Issuer	Guarantor			$ million 2016
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Operating activities					
Profit (loss) before taxation	44	168	(1,645)	(862)	(2,295)
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities					
Exploration expenditure written off	—	—	1,274	—	1,274
Depreciation, depletion and amortization	673	—	13,832	—	14,505
Impairment and (gain) loss on sale of businesses and fixed assets	(148)	—	(2,648)	—	(2,796)
Earnings from joint ventures and associates	—	—	(1,960)	—	(1,960)
Dividends received from joint ventures and associates	—	—	1,105	—	1,105
Equity accounted income of subsidiaries- after interest and tax	—	(862)	—	862	—
Dividends received from (paid to) subsidiaries	(7,000)	372	—	6,628	—
Interest receivable	(94)	(233)	(593)	720	(200)
Interest received	94	233	660	(720)	267
Finance costs	103	311	1,981	(720)	1,675
Interest paid	(103)	(311)	(1,443)	720	(1,137)
Net finance expense relating to pensions and other post-retirement benefits	—	(82)	272	—	190
Share-based payments	—	780	(1)	—	779
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	—	(192)	(275)	—	(467)
Net charge for provisions, less payments	77	—	4,410	—	4,487
(Increase) decrease in inventories	(3)	—	(3,678)	—	(3,681)
(Increase) decrease in other current and non-current assets	6,985	(156)	(1,001)	(7,000)	(1,172)
Increase (decrease) in other current and non-current liabilities	(33)	4,634	(2,946)	—	1,655
Income taxes paid	104	(1)	(1,641)	—	(1,538)
Net cash provided by operating activities	699	4,661	5,703	(372)	10,691
Investing activities					
Expenditure on property, plant and equipment, intangible and other assets	(699)	—	(16,002)	—	(16,701)
Acquisitions, net of cash acquired	—	—	(1)	—	(1)
Investment in joint ventures	—	—	(50)	—	(50)
Investment in associates	—	—	(700)	—	(700)
Total cash capital expenditure	(699)	—	(16,753)	—	(17,452)
Proceeds from disposals of fixed assets	—	—	1,372	—	1,372
Proceeds from disposals of businesses, net of cash disposed	—	—	1,259	—	1,259
Proceeds from loan repayments	—	—	68	—	68
Net cash provided by (used in) investing activities	(699)	—	(14,054)	—	(14,753)
Financing activities					
Proceeds from long-term financing	—	—	12,442	—	12,442
Repayments of long-term financing	—	—	(6,685)	—	(6,685)
Net increase (decrease) in short-term debt	—	—	51	—	51
Net increase (decrease) in non-controlling interests	—	—	887	—	887
Dividends paid					
BP shareholders	—	(4,611)	(372)	372	(4,611)
Non-controlling interests	—	—	(107)	—	(107)
Net cash provided by (used in) financing activities	—	(4,611)	6,216	372	1,977
Currency translation differences relating to cash and cash equivalents	—	—	(820)	—	(820)
Increase (decrease) in cash and cash equivalents	—	50	(2,955)	—	(2,905)
Cash and cash equivalents at beginning of year	—	—	26,389	—	26,389
Cash and cash equivalents at end of year	—	50	23,434	—	23,484

Supplementary information on oil and natural gas (unaudited)

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 285-290.

Oil and natural gas exploration and production activities

										$ million
										2018
	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	29,730	—	89,069	3,385	14,269	51,980	—	38,315	6,119	232,867
Unproved properties	451	—	3,602	2,667	2,742	3,870	—	3,153	568	17,053
	30,181	—	92,671	6,052	17,011	55,850	—	41,468	6,687	249,920
Accumulated depreciation	16,809	—	47,051	420	8,517	38,324	—	20,173	3,626	134,920
Net capitalized costs	13,372	—	45,620	5,632	8,494	17,526	—	21,295	3,061	115,000
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	1,933	—	10,650	—	—	(1)	—	36	—	12,618
Unproved	—	—	35	—	100	50	—	(5)	—	180
	1,933	—	10,685	—	100	49	—	31	—	12,798
Exploration and appraisal costs[c]	238	—	216	139	245	283	5	148	24	1,298
Development	817	—	3,429	46	591	2,340	—	2,458	236	9,917
Total costs	2,988	—	14,330	185	936	2,672	5	2,637	260	24,013
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[d]										
Third parties	619	—	1,306	105	2,074	3,228	—	1,430	1,410	10,172
Sales between businesses	2,255	—	11,656	1	195	3,928	—	7,793	665	26,493
	2,874	—	12,962	106	2,269	7,156	—	9,223	2,075	36,665
Exploration expenditure	105	—	509	146	252	405	5	20	3	1,445
Production costs	646	—	2,729	120	430	1,066	—	951	138	6,080
Production taxes	(269)	—	369	—	357	—	—	1,010	69	1,536
Other costs (income)[e]	(331)	(2)	2,379	43	165	133	42	94	223	2,746
Depreciation, depletion and amortization	1,199	—	3,921	101	1,023	3,635	—	2,165	298	12,342
Net impairments and (gains) losses on sale of businesses and fixed assets	(226)	—	203	10	—	(141)	—	21	136	3
	1,124	(2)	10,110	420	2,227	5,098	47	4,261	867	24,152
Profit (loss) before taxation[f]	1,750	2	2,852	(314)	42	2,058	(47)	4,962	1,208	12,513
Allocable taxes[g]	446	—	454	(95)	314	1,184	13	3,509	508	6,333
Results of operations	1,304	2	2,398	(219)	(272)	874	(60)	1,453	700	6,180
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax										
Exploration and production activities – subsidiaries (as above)	1,750	2	2,852	(314)	42	2,058	(47)	4,962	1,208	12,513
Midstream and other activities – subsidiaries[h]	(20)	265	188	(111)	135	(58)	5	463	6	873
Equity-accounted entities[i j]	(2)	130	28	—	209	207	2,346	245	—	3,163
Total replacement cost profit (loss) before interest and tax	1,728	397	3,068	(425)	386	2,207	2,304	5,670	1,214	16,549

[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, Asia and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.

[b] Costs of decommissioning 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 $17 million. The UK region includes a $384-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 $208 million which is included in finance costs in the group income statement.

[g] US region includes the deferred tax impact of the reduction in the US Federal corporate income tax rate from 35% to 21% enacted in December 2017.

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

[i] The profits of equity-accounted entities are included after interest and tax.

[j] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation.

Oil and natural gas exploration and production activities – continued

										$ million
										2018
	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	—	3,439	—	—	9,643	—	24,052	3,646	—	40,780
Unproved properties	—	657	—	—	86	—	828	26	—	1,597
	—	4,096	—	—	9,729	—	24,880	3,672	—	42,377
Accumulated depreciation	—	670	—	—	4,665	—	6,749	3,672	—	15,756
Net capitalized costs	—	3,426	—	—	5,064	—	18,131	—	—	26,621
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	425	—	—	425
Unproved	—	137	—	—	—	—	148	—	—	285
	—	137	—	—	—	—	573	—	—	710
Exploration and appraisal costs[d]	—	67	—	—	25	—	207	—	—	299
Development	—	251	—	—	575	—	3,255	212	—	4,293
Total costs	—	455	—	—	600	—	4,035	212	—	5,302
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	—	1,114	—	—	1,792	—	—	353	—	3,259
Sales between businesses	—	—	—	—	—	—	15,901	—	—	15,901
	—	1,114	—	—	1,792	—	15,901	353	—	19,160
Exploration expenditure	—	89	—	—	7	—	112	—	—	208
Production costs	—	207	—	—	438	—	1,487	39	—	2,171
Production taxes	—	—	—	—	361	—	7,634	94	—	8,089
Other costs (income)	—	21	—	—	127	—	638	—	—	786
Depreciation, depletion and amortization	—	290	—	—	416	—	1,627	212	—	2,545
Net impairments and losses on sale of businesses and fixed assets	—	6	—	—	—	—	47	1	—	54
	—	613	—	—	1,349	—	11,545	346	—	13,853
Profit (loss) before taxation	—	501	—	—	443	—	4,356	7	—	5,307
Allocable taxes	—	350	—	—	279	—	849	—	—	1,478
Results of operations[g]	—	151	—	—	164	—	3,507	7	—	3,829
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax from equity-accounted entities										
Exploration and production activities – equity-accounted entities after tax (as above)	—	151	—	—	164	—	3,507	7	—	3,829
Midstream and other activities after tax[h]	(2)	(21)	28	—	45	207	(1,161)	238	—	(666)
Total replacement cost profit (loss) after interest and tax	(2)	130	28	—	209	207	2,346	245	—	3,163

[a] Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia. The amounts reported include the corresponding amounts for their equity-accounted entities.

[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 and Pan American Energy Group are excluded.

[c] Costs of decommissioning 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] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation.

[h] Includes interest and adjustment for non-controlling interests. Excludes inventory holding gains and losses.

Oil and natural gas exploration and production activities – continued

	Europe		North America		South America	Africa	Asia		Australasia	Total
										$ million
										2017
	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	34,208	—	83,449	3,518	13,581	49,795	—	35,519	5,984	226,054
Unproved properties	481	—	3,957	2,561	2,905	4,013	—	3,407	562	17,886
	34,689	—	87,406	6,079	16,486	53,808	—	38,926	6,546	243,940
Accumulated depreciation	21,793	—	48,462	367	7,495	34,870	—	18,007	3,192	134,186
Net capitalized costs	12,896	—	38,944	5,712	8,991	18,938	—	20,919	3,354	109,754
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	—	—	22	—	—	564	—	1,187	—	1,773
Unproved	13	—	13	—	330	374	—	228	—	958
	13	—	35	—	330	938	—	1,415	—	2,731
Exploration and appraisal costs[c]	336	—	102	52	264	682	11	190	18	1,655
Development	995	—	2,776	58	911	2,972	—	2,760	223	10,695
Total costs	1,344	—	2,913	110	1,505	4,592	11	4,365	241	15,081
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[d]										
Third parties	204	—	724	171	1,134	2,211	—	1,276	967	6,687
Sales between businesses	1,745	—	9,117	2	327	4,022	—	6,394	487	22,094
	1,949	—	9,841	173	1,461	6,233	—	7,670	1,454	28,781
Exploration expenditure	331	—	282	39	83	1,346	11	(29)	17	2,080
Production costs	629	—	2,256	116	573	979	—	904	157	5,614
Production taxes	(37)	—	52	—	86	—	—	1,618	56	1,775
Other costs (income)[e]	(272)	2	1,655	34	71	280	39	311	349	2,469
Depreciation, depletion and amortization	1,190	—	4,258	96	742	3,586	—	2,147	366	12,385
Net impairments and (gains) losses on sale of businesses and fixed assets	133	(12)	87	(1)	(31)	—	—	(10)	13	179
	1,974	(10)	8,590	284	1,524	6,191	50	4,941	958	24,502
Profit (loss) before taxation[f]	(25)	10	1,251	(111)	(63)	42	(50)	2,729	496	4,279
Allocable taxes[g]	(104)	—	(1,811)	(28)	155	788	(19)	1,505	146	632
Results of operations	79	10	3,062	(83)	(218)	(746)	(31)	1,224	350	3,647
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax										
Exploration and production activities – subsidiaries (as above)	(25)	10	1,251	(111)	(63)	42	(50)	2,729	496	4,279
Midstream and other activities – subsidiaries[h]	(185)	97	(176)	(111)	140	(80)	3	315	11	14
Equity-accounted entities[i j]	—	71	25	—	381	205	837	245	—	1,764
Total replacement cost profit (loss) before interest and tax	(210)	178	1,100	(222)	458	167	790	3,289	507	6,057

[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, Asia and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the South Caucasus Pipeline, the Forties Pipeline System and the Baku-Tbilisi-Ceyhan pipeline. The Forties Pipeline System was divested on 31 October 2017. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.

[b] Costs of decommissioning 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 $32 million. The UK region includes a $343-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 $120 million which is included in finance costs in the group income statement.

[g] US region includes the deferred tax impact of the reduction in the US Federal corporate income tax rate from 35% to 21% enacted in December 2017.

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

[i] The profits of equity-accounted entities are included after interest and tax.

[j] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation. Of BP's initial 60% interest in PAE, 10% was classified as held for sale on 9 September 2017. For September, only 9 days of income was reported for the full 60%. After this equity accounting continued for the 50% not classified as held for sale. BP accounted for 50% of the enlarged entity from 16 December 2017.

										$ million
										2017
	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	—	3,187	—	—	9,096	—	24,686	3,434	—	40,403
Unproved properties	—	481	—	—	68	—	907	26	—	1,482
	—	3,668	—	—	9,164	—	25,593	3,460	—	41,885
Accumulated depreciation	—	400	—	—	4,249	—	6,207	3,460	—	14,316
Net capitalized costs	—	3,268	—	—	4,915	—	19,386	—	—	27,569
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	323	—	—	—	—	653	—	—	976
Unproved	—	152	—	—	20	—	416	—	—	588
	—	475	—	—	20	—	1,069	—	—	1,564
Exploration and appraisal costs[d]	—	49	—	—	43	—	194	—	—	286
Development	—	199	—	—	576	—	3,361	446	—	4,582
Total costs	—	723	—	—	639	—	4,624	446	—	6,432
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	—	773	—	—	1,750	—	—	988	—	3,511
Sales between businesses	—	—	—	—	—	—	11,537	—	—	11,537
	—	773	—	—	1,750	—	11,537	988	—	15,048
Exploration expenditure	—	68	—	—	—	—	59	—	—	127
Production costs	—	157	—	—	592	—	1,424	117	—	2,290
Production taxes	—	—	—	—	336	—	5,712	426	—	6,474
Other costs (income)	—	67	—	—	11	—	409	(5)	—	482
Depreciation, depletion and amortization	—	328	—	—	458	—	1,539	446	—	2,771
Net impairments and losses on sale of businesses and fixed assets	—	6	—	—	27	—	54	—	—	87
	—	626	—	—	1,424	—	9,197	984	—	12,231
Profit (loss) before taxation	—	147	—	—	326	—	2,340	4	—	2,817
Allocable taxes	—	54	—	—	(18)	—	457	—	—	493
Results of operations[g]	—	93	—	—	344	—	1,883	4	—	2,324
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax from equity-accounted entities										
Exploration and production activities – equity-accounted entities after tax (as above)	—	93	—	—	344	—	1,883	4	—	2,324
Midstream and other activities after tax[h]	—	(22)	25	—	37	205	(1,046)	241	—	(560)
Total replacement cost profit (loss) after interest and tax	—	71	25	—	381	205	837	245	—	1,764

[a] Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia. The amounts reported include the corresponding amounts for their equity-accounted entities.

[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 and Pan American Energy Group are excluded.

[c] Costs of decommissioning 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] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation. Of BP's initial 60% interest in PAE, 10% was classified as held for sale on 9 September 2017. For September, only 9 days of income was reported for the full 60%. After this equity accounting continued for the 50% not classified as held for sale. BP accounted for 50% of the enlarged entity from 16 December 2017.

[h] Includes interest and adjustment for non-controlling interests. Excludes inventory holding gains and losses.

										$ million
										2016
	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	34,171	—	81,633	3,622	12,624	46,892	—	30,870	5,752	215,564
Unproved properties	483	—	4,712	2,377	2,450	3,808	—	4,132	562	18,524
	34,654	—	86,345	5,999	15,074	50,700	—	35,002	6,314	234,088
Accumulated depreciation	21,745	—	44,988	272	6,764	31,456	—	15,942	2,826	123,993
Net capitalized costs	12,909	—	41,357	5,727	8,310	19,244	—	19,060	3,488	110,095
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties[c]										
Proved	215	—	314	—	—	—	—	703	207	1,439
Unproved	—	—	38	10	10	181	—	1,728	—	1,967
	215	—	352	10	10	181	—	2,431	207	3,406
Exploration and appraisal costs[d]	165	5	391	70	123	297	10	252	89	1,402
Development	1,284	3	2,372	28	1,519	2,957	—	2,788	194	11,145
Total costs	1,664	8	3,115	108	1,652	3,435	10	5,471	490	15,953
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[e]										
Third parties	244	26	640	74	747	1,215	—	97	1,042	4,085
Sales between businesses	1,387	421	6,204	2	103	3,391	—	3,908	309	15,725
	1,631	447	6,844	76	850	4,606	—	4,005	1,351	19,810
Exploration expenditure	133	3	693	61	672	87	10	(27)	89	1,721
Production costs	619	208	2,524	114	476	1,220	—	691	154	6,006
Production taxes	(351)	—	155	—	38	—	—	800	41	683
Other costs (income)[f]	(215)	37	1,687	25	115	597	34	115	153	2,548
Depreciation, depletion and amortization	1,002	209	3,940	66	591	2,937	—	2,179	289	11,213
Net impairments and (gains) losses on sale of businesses and fixed assets	(809)	(345)	(627)	(5)	(77)	(765)	—	(182)	63	(2,747)
	379	112	8,372	261	1,815	4,076	44	3,576	789	19,424
Profit (loss) before taxation[g]	1,252	335	(1,528)	(185)	(965)	530	(44)	429	562	386
Allocable taxes[h]	(286)	(287)	(402)	(40)	(194)	670	(10)	(74)	288	(335)
Results of operations	1,538	622	(1,126)	(145)	(771)	(140)	(34)	503	274	721
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax										
Exploration and production activities – subsidiaries (as above)	1,252	335	(1,528)	(185)	(965)	530	(44)	429	562	386
Midstream and other activities – subsidiaries[i]	(417)	54	(14)	(137)	187	(142)	(2)	(81)	13	(539)
Equity-accounted entities[j k]	—	(1)	20	—	447	(12)	597	266	—	1,317
Total replacement cost profit (loss) before interest and tax	835	388	(1,522)	(322)	(331)	376	551	614	575	1,164

[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, Asia 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] Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c] Rest of Asia amounts include BP's participating interest in the Abu Dhabi ADCO concession.

[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] 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 $32 million. The UK region includes a $454-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 $152 million which is included in finance costs in the group income statement.

[h] UK region includes the 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 20% to 10%.

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

[j] The profits of equity-accounted entities are included after interest and tax.

[k] Includes the results of BP's 30% interest in Aker BP ASA from 1 October 2016.

Oil and natural gas exploration and production activities – continued

										$ million
										2016
	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	—	2,702	—	—	10,211	—	19,558	3,009	—	35,480
Unproved properties	—	296	—	—	6	—	383	26	—	711
	—	2,998	—	—	10,217	—	19,941	3,035	—	36,191
Accumulated depreciation	—	48	—	—	4,615	—	4,401	3,035	—	12,099
Net capitalized costs	—	2,950	—	—	5,602	—	15,540	—	—	24,092
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	1,576	—	—	1,576
Unproved	—	—	—	—	—	—	69	—	—	69
	—	—	—	—	—	—	1,645	—	—	1,645
Exploration and appraisal costs[d]	—	18	—	—	7	—	118	1	—	144
Development	—	54	—	—	559	—	2,070	371	—	3,054
Total costs	—	72	—	—	566	—	3,833	372	—	4,843
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	—	162	—	—	1,865	—	—	876	—	2,903
Sales between businesses	—	—	—	—	—	—	8,088	16	—	8,104
	—	162	—	—	1,865	—	8,088	892	—	11,007
Exploration expenditure	—	13	—	—	—	—	50	—	—	63
Production costs	—	36	—	—	559	—	1,085	145	—	1,825
Production taxes	—	—	—	—	335	—	3,393	352	—	4,080
Other costs (income)	—	(13)	—	—	(429)	—	345	3	—	(94)
Depreciation, depletion and amortization	—	48	—	—	499	—	1,082	386	—	2,015
Net impairments and losses on sale of businesses and fixed assets	—	—	—	—	164	—	59	—	—	223
	—	84	—	—	1,128	—	6,014	886	—	8,112
Profit (loss) before taxation	—	78	—	—	737	—	2,074	6	—	2,895
Allocable taxes	—	75	—	—	319	—	435	3	—	832
Results of operations[g]	—	3	—	—	418	—	1,639	3	—	2,063
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax from equity-accounted entities										
Exploration and production activities – equity-accounted entities after tax (as above)	—	3	—	—	418	—	1,639	3	—	2,063
Midstream and other activities after tax[h]	—	(4)	20	—	29	(12)	(1,042)	263	—	(746)
Total replacement cost profit (loss) after interest and tax	—	(1)	20	—	447	(12)	597	266	—	1,317

[a] Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia. The amounts reported include the corresponding amounts for their equity-accounted entities. Amounts also include certain adjustments, mainly related to purchase price allocations for 2016 acquisitions.

[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.

[c] Costs of decommissioning 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 the results of BP's 30% interest in Aker BP ASA from 1 October 2016.

[h] Includes interest and adjustment for non-controlling interests. Excludes inventory holding gains and losses.

Movements in estimated net proved reserves

million barrels

Crude oil[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
2018	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	245	—	932	54	10	281	—	1,040	31	2,592
Undeveloped	164	—	492	195	6	28	—	642	11	1,537
	409	—	1,423	248	16	309	—	1,682	42	4,129
Changes attributable to										
Revisions of previous estimates	22	—	116	(6)	1	11	—	40	(2)	183
Improved recovery	—	—	51	—	—	1	—	—	—	52
Purchases of reserves-in-place	93	—	412	—	—	—	—	—	—	504
Discoveries and extensions	15	—	17	—	—	13	—	—	—	46
Production[d]	(37)	—	(137)	(9)	(3)	(75)	—	(114)	(6)	(381)
Sales of reserves-in-place	(37)	—	(118)	—	—	—	—	—	—	(155)
	57	—	341	(15)	(2)	(50)	—	(74)	(8)	249
At 31 December[e]										
Developed	223	—	962	43	8	223	—	1,126	30	2,615
Undeveloped	243	—	802	190	5	36	—	482	5	1,763
	466	—	1,764	234	14	259	—	1,608	34	4,378
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	56	—	—	285	1	3,124	6	—	3,473
Undeveloped	—	89	—	—	263	—	2,251	—	—	2,603
	—	145	—	—	548	1	5,374	6	—	6,076
Changes attributable to										
Revisions of previous estimates	—	11	—	—	7	—	150	—	—	168
Improved recovery	—	13	—	—	—	—	—	—	—	13
Purchases of reserves-in-place	—	—	—	—	—	—	89	—	—	89
Discoveries and extensions	—	—	—	19	21	—	326	—	—	366
Production	—	(13)	—	—	(25)	—	(335)	(6)	—	(379)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	12	—	19	4	(1)	229	(6)	—	257
At 31 December[g]										
Developed	—	57	—	—	293	1	3,190	—	—	3,541
Undeveloped	—	100	—	19	259	—	2,414	—	—	2,792
	—	157	—	19	552	1	5,604	—	—	6,333
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	245	56	932	54	295	282	3,124	1,047	31	6,064
Undeveloped	164	89	492	195	269	28	2,251	642	11	4,140
	409	145	1,423	249	564	310	5,374	1,688	42	10,205
At 31 December										
Developed	223	57	962	43	302	224	3,190	1,126	30	6,156
Undeveloped	243	100	802	209	264	36	2,414	482	5	4,555
	466	157	1,764	253	566	260	5,604	1,608	34	10,711

[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 16 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 4 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 344 million barrels of crude oil in respect of the 6.28% non-controlling interest in Rosneft, including 24 mmbbl held through BP's interests in Russia other than Rosneft.

[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 5,539 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 58 million barrels in Venezuela and 5,481 million barrels in Russia.

Movements in estimated net proved reserves- continued

										million barrels
Natural gas liquids[a b]										2018
	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	11	—	177	—	2	21	—	—	5	216
Undeveloped	3	—	69	—	28	—	—	—	1	102
	14	—	246	—	30	21	—	—	6	318
Changes attributable to										
Revisions of previous estimates	1	—	20	—	—	(3)	—	—	—	17
Improved recovery	—	—	16	—	—	2	—	—	—	18
Purchases of reserves-in-place	—	—	253	—	—	—	—	—	—	253
Discoveries and extensions	3	—	1	—	—	3	—	—	—	7
Production[c]	(2)	—	(25)	—	(3)	(3)	—	—	(1)	(34)
Sales of reserves-in-place	(3)	—	—	—	—	—	—	—	—	(3)
	—	—	265	—	(3)	(2)	—	—	(1)	258
At 31 December[d]										
Developed	8	—	266	—	2	14	—	—	5	295
Undeveloped	6	—	246	—	25	4	—	—	—	280
	14	—	511	—	27	18	—	—	5	576
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	4	—	—	—	10	82	—	—	97
Undeveloped	—	4	—	—	—	—	49	—	—	53
	—	8	—	—	—	10	131	—	—	149
Changes attributable to										
Revisions of previous estimates	—	—	—	—	—	(1)	25	—	—	23
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(1)	(2)	—	—	(4)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	(1)	—	—	—	(3)	23	—	—	19
At 31 December[f]										
Developed	—	4	—	—	—	7	103	—	—	114
Undeveloped	—	3	—	—	—	—	51	—	—	54
	—	7	—	—	—	7	154	—	—	169
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	11	4	177	—	2	31	82	—	5	313
Undeveloped	3	4	69	—	28	—	49	—	1	154
	14	8	246	—	30	31	131	—	6	467
At 31 December										
Developed	8	4	266	—	2	22	103	—	5	409
Undeveloped	6	3	246	—	25	4	51	—	—	335
	14	7	511	—	27	26	154	—	5	744

[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 3 thousand barrels per day for equity-accounted entities.

[d] Includes 8 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] Includes 12 million barrels of NGLs in respect of the 7.82% non-controlling interest in Rosneft.

[f] Total proved NGL reserves held as part of our equity interest in Rosneft is 154 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 154 million barrels in Russia.

Movements in estimated net proved reserves- continued

million barrels

Total liquids[a b]										2018
	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	256	—	1,108	54	12	301	—	1,040	36	2,808
Undeveloped	167	—	561	195	34	28	—	642	12	1,639
	424	—	1,669	248	46	329	—	1,682	48	4,447
Changes attributable to										
Revisions of previous estimates	23	—	136	(6)	1	8	—	40	(2)	200
Improved recovery	—	—	67	—	—	3	—	—	—	70
Purchases of reserves-in-place	93	—	665	—	—	—	—	—	—	758
Discoveries and extensions	18	—	18	—	—	16	—	—	—	52
Production[d]	(39)	—	(162)	(9)	(6)	(79)	—	(114)	(7)	(415)
Sales of reserves-in-place	(40)	—	(118)	—	—	—	—	—	—	(158)
	56	—	606	(15)	(5)	(52)	—	(74)	(9)	507
At 31 December[e]										
Developed	231	—	1,228	43	10	237	—	1,126	35	2,910
Undeveloped	249	—	1,048	190	30	40	—	482	5	2,044
	480	—	2,276	234	41	277	—	1,608	39	4,954
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	60	—	—	285	11	3,206	6	—	3,569
Undeveloped	—	93	—	—	263	—	2,300	—	—	2,656
	—	153	—	—	548	12	5,505	6	—	6,225
Changes attributable to										
Revisions of previous estimates	—	11	—	—	7	(2)	175	—	—	191
Improved recovery	—	13	—	—	—	—	—	—	—	13
Purchases of reserves-in-place	—	—	—	—	—	—	89	—	—	89
Discoveries and extensions	—	—	—	19	21	—	326	—	—	366
Production	—	(13)	—	—	(25)	(2)	(337)	(6)	—	(383)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	11	—	19	4	(3)	253	(6)	—	277
At 31 December[g h]										
Developed	—	60	—	—	293	8	3,293	—	—	3,655
Undeveloped	—	104	—	19	259	—	2,465	—	—	2,846
	—	164	—	19	552	8	5,758	—	—	6,502
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	256	60	1,108	54	297	313	3,206	1,047	36	6,377
Undeveloped	167	93	561	195	297	28	2,300	642	12	4,295
	424	153	1,669	249	594	341	5,505	1,688	48	10,672
At 31 December										
Developed	231	60	1,228	44	303	245	3,293	1,126	35	6,565
Undeveloped	249	104	1,048	209	289	40	2,465	482	5	4,890
	480	164	2,276	253	593	285	5,758	1,608	39	11,456

[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 16 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 3 thousand barrels per day for equity-accounted entities.

[e] Also includes 12 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 356 million barrels in respect of the non-controlling interest in Rosneft, including 24 mmboe held through BP's interests in Russia other than Rosneft.

[h] Total proved liquid reserves held as part of our equity interest in Rosneft is 5,693 million barrels, comprising less than 1 million barrels in Canada, 58 million barrels in Venezuela, less than 1 million barrels in Vietnam and 5,635 million barrels in Russia.

Movements in estimated net proved reserves – continued

billion cubic feet

Natural gas[a b]										2018
	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	523	—	5,238	(1)	2,862	1,159	—	2,755	2,730	15,266
Undeveloped	320	—	3,086	—	3,330	1,510	—	4,245	1,505	13,997
	843	—	8,323	(1)	6,193	2,670	—	7,000	4,235	29,263
Changes attributable to										
Revisions of previous estimates	84	—	10	3	(195)	(444)	—	140	(123)	(524)
Improved recovery	—	—	1,315	—	—	—	—	—	—	1,315
Purchases of reserves-in-place	40	—	2,655	—	—	—	—	—	—	2,695
Discoveries and extensions	60	—	11	—	31	578	—	—	—	680
Production[c]	(66)	—	(751)	(3)	(788)	(423)	—	(324)	(303)	(2,658)
Sales of reserves-in-place	(178)	—	(237)	—	—	—	—	—	—	(416)
	(61)	—	3,003	1	(951)	(290)	—	(184)	(426)	1,092
At 31 December[d]										
Developed	439	—	6,270	—	2,168	1,313	—	3,599	2,630	16,420
Undeveloped	343	—	5,056	—	3,073	1,067	—	3,218	1,179	13,936
	782	—	11,326	—	5,241	2,380	—	6,817	3,809	30,355
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	112	—	—	1,274	476	6,077	17	—	7,955
Undeveloped	—	69	—	—	450	146	7,173	3	—	7,841
	—	180	—	—	1,724	622	13,250	20	—	15,796
Changes attributable to										
Revisions of previous estimates	—	2	—	—	(50)	(39)	805	2	—	719
Improved recovery	—	—	—	—	1	—	—	—	—	1
Purchases of reserves-in-place	—	—	—	—	—	—	2,413	—	—	2,413
Discoveries and extensions	—	—	—	4	122	—	512	—	—	638
Production[c]	—	(22)	—	—	(145)	(48)	(464)	(6)	—	(685)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	(19)	—	3	(71)	(87)	3,267	(5)	—	3,087
At 31 December[f g]										
Developed	—	107	—	—	1,207	391	7,798	12	—	9,515
Undeveloped	—	55	—	4	446	143	8,719	4	—	9,369
	—	161	—	4	1,653	534	16,517	15	—	18,884
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	523	112	5,238	—	4,136	1,635	6,077	2,771	2,730	23,221
Undeveloped	320	69	3,086	—	3,781	1,656	7,173	4,249	1,505	21,838
	843	180	8,323	—	7,917	3,291	13,250	7,020	4,235	45,060
At 31 December										
Developed	439	107	6,270	—	3,375	1,704	7,798	3,610	2,630	25,934
Undeveloped	343	55	5,056	4	3,519	1,210	8,719	3,221	1,179	23,305
	782	161	11,326	4	6,894	2,914	16,517	6,832	3,809	49,239

[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, 139 billion cubic feet in subsidiaries, 42 billion cubic feet in equity-accounted entities.

[d] Includes 1,573 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 1,211 billion cubic feet of natural gas in respect of the 8.60% non-controlling interest in Rosneft including 480 billion cubic feet held through BP's interests in Russia other than Rosneft.

[g] Total proved gas reserves held as part of our equity interest in Rosneft is 14,325 billion cubic feet, comprising 0 billion cubic feet in Canada, 26 billion cubic feet in Venezuela, 15 billion cubic feet in Vietnam, 200 billion cubic feet in Egypt and 14,084 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

										million barrels of oil equivalent[c]
Total hydrocarbons[a b]										2018
	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	347	–	2,011	54	505	501	–	1,515	507	5,440
Undeveloped	222	–	1,093	195	608	288	–	1,374	272	4,052
	569	–	3,104	248	1,114	790	–	2,889	779	9,492
Changes attributable to										
Revisions of previous estimates	38	–	138	(5)	(33)	(69)	–	64	(23)	110
Improved recovery	–	–	294	–	–	3	–	–	–	297
Purchases of reserves-in-place	100	–	1,123	–	–	–	–	–	–	1,222
Discoveries and extensions	29	–	20	–	5	116	–	–	–	169
Production[e f]	(50)	–	(292)	(9)	(142)	(152)	–	(170)	(59)	(874)
Sales of reserves-in-place	(70)	–	(159)	–	–	–	–	–	–	(229)
	46	–	1,124	(15)	(169)	(102)	–	(106)	(82)	696
At 31 December[g]										
Developed	307	–	2,309	43	384	464	–	1,746	488	5,741
Undeveloped	308	–	1,919	190	560	224	–	1,037	208	4,447
	615	–	4,228	234	944	687	–	2,783	696	10,188
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed	–	80	–	–	505	93	4,254	9	–	4,941
Undeveloped	–	105	–	–	341	25	3,536	1	–	4,008
	–	184	–	–	846	119	7,790	10	–	8,949
Changes attributable to										
Revisions of previous estimates	–	11	–	–	(1)	(8)	313	–	–	315
Improved recovery	–	13	–	–	–	–	–	–	–	14
Purchases of reserves-in-place	–	–	–	–	–	–	505	–	–	505
Discoveries and extensions	–	–	–	20	42	–	414	–	–	476
Production[e]	–	(17)	–	–	(50)	(10)	(417)	(7)	–	(501)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	8	–	19	(9)	(18)	816	(7)	–	809
At 31 December[i j]										
Developed	–	79	–	–	501	76	4,638	2	–	5,296
Undeveloped	–	113	–	20	336	25	3,968	1	–	4,462
	–	192	–	20	837	101	8,605	3	–	9,757
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	347	80	2,011	54	1,010	595	4,254	1,524	507	10,381
Undeveloped	222	105	1,093	195	949	314	3,536	1,374	272	8,060
	569	184	3,104	249	1,959	908	7,790	2,899	779	18,441
At 31 December										
Developed	307	79	2,309	44	885	539	4,638	1,749	488	11,037
Undeveloped	308	113	1,919	210	896	249	3,968	1,037	208	8,908
	615	192	4,228	253	1,781	788	8,605	2,786	696	19,945

[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 16 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 3 thousand barrels per day for equity-accounted entities.

[f] Includes 31 million barrels of oil equivalent of natural gas consumed in operations, 24 million barrels of oil equivalent in subsidiaries, 7 million barrels of oil equivalent in equity-accounted entities.

[g] Includes 283 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 565 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 107 mmboe held through BP's interests in Russia other than Rosneft.

[j] Total proved reserves held as part of our equity interest in Rosneft is 8,163 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada, 62 million barrels of oil equivalent in Venezuela, 3 million barrels of oil equivalent in Vietnam, 35 million barrels of oil equivalent in Egypt and 8,063 million barrels of oil equivalent in Russia.

Movements in estimated net proved reserves – continued

Crude oil[a b]										million barrels 2017
	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	155	—	826	42	9	317	—	1,107	32	2,487
Undeveloped	274	—	497	209	11	42	—	245	14	1,291
	429	—	1,322	251	20	358	—	1,352	46	3,778
Changes attributable to										
Revisions of previous estimates	15	—	208	5	1	35	—	407	2	673
Improved recovery	—	—	12	—	—	2	—	—	—	14
Purchases of reserves-in-place	3	—	1	—	—	1	—	—	—	5
Discoveries and extensions	—	—	12	—	—	—	—	42	—	53
Production[d]	(29)	—	(131)	(7)	(5)	(88)	—	(119)	(6)	(384)
Sales of reserves-in-place	(9)	—	—	—	—	—	—	—	—	(9)
	(20)	—	101	(2)	(4)	(50)	—	330	(4)	351
At 31 December[e]										
Developed	245	—	932	54	10	281	—	1,040	31	2,592
Undeveloped	164	—	492	195	6	28	—	642	11	1,537
	409	—	1,423	248	16	309	—	1,682	42	4,129
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	45	—	—	321	1	3,162	43	—	3,573
Undeveloped	—	69	—	—	325	—	2,134	1	—	2,529
	—	114	—	—	646	1	5,296	44	—	6,101
Changes attributable to										
Revisions of previous estimates	—	2	—	—	1	—	102	(1)	—	104
Improved recovery	—	11	—	—	4	—	—	—	—	16
Purchases of reserves-in-place	—	34	—	—	—	—	37	—	—	71
Discoveries and extensions	—	1	—	—	22	—	264	—	—	288
Production	—	(11)	—	—	(28)	—	(325)	(36)	—	(401)
Sales of reserves-in-place	—	(5)	—	—	(98)	—	—	—	—	(103)
	—	31	—	—	(98)	—	78	(37)	—	(25)
At 31 December[g]										
Developed	—	56	—	—	285	1	3,124	6	—	3,473
Undeveloped	—	89	—	—	263	—	2,251	—	—	2,603
	—	145	—	—	548	1	5,374	6	—	6,076
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	155	45	826	42	330	318	3,162	1,150	32	6,060
Undeveloped	274	69	497	209	336	42	2,134	246	14	3,819
	429	114	1,322	251	666	360	5,296	1,395	46	9,879
At 31 December										
Developed	245	56	932	54	295	282	3,124	1,047	31	6,064
Undeveloped	164	89	492	195	269	28	2,251	642	11	4,140
	409	145	1,423	249	564	310	5,374	1,688	42	10,205

[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 9 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 5 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 337 million barrels of crude oil in respect of the 6.31% non-controlling interest in Rosneft, including 6 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 5,402 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 59 million barrels in Venezuela and 5,342 million barrels in Russia.

										million barrels
Natural gas liquids[a b]										2017
	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	13	—	226	—	5	13	—	—	9	266
Undeveloped	3	—	73	—	28	1	—	—	2	107
	16	—	299	—	33	14	—	—	11	373
Changes attributable to										
Revisions of previous estimates	2	—	(44)	—	—	11	—	—	(4)	(36)
Improved recovery	—	—	15	—	—	—	—	—	—	15
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	1	—	—	—	—	—	—	1
Production[c]	(3)	—	(24)	—	(3)	(4)	—	—	(1)	(35)
Sales of reserves-in-place	(1)	—	—	—	—	—	—	—	—	(1)
	(2)	—	(52)	—	(3)	7	—	—	(5)	(55)
At 31 December[d]										
Developed	11	—	177	—	2	21	—	—	5	216
Undeveloped	3	—	69	—	28	—	—	—	1	102
	14	—	246	—	30	21	—	—	6	318
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	3	—	—	—	11	50	—	—	65
Undeveloped	—	2	—	—	—	—	15	—	—	17
	—	5	—	—	—	11	65	—	—	81
Changes attributable to										
Revisions of previous estimates	—	—	—	—	—	1	68	—	—	69
Improved recovery	—	1	—	—	—	—	—	—	—	1
Purchases of reserves-in-place	—	2	—	—	—	—	—	—	—	2
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(1)	(2)	—	—	(4)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	3	—	—	—	(1)	66	—	—	68
At 31 December[f]										
Developed	—	4	—	—	—	10	82	—	—	97
Undeveloped	—	4	—	—	—	—	49	—	—	53
	—	8	—	—	—	10	131	—	—	149
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	13	3	226	—	5	24	50	—	9	331
Undeveloped	3	2	73	—	28	1	15	—	2	123
	16	5	299	—	33	25	65	—	11	454
At 31 December										
Developed	11	4	177	—	2	31	82	—	5	313
Undeveloped	3	4	69	—	28	—	49	—	1	154
	14	8	246	—	30	31	131	—	6	467

[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 2 thousand barrels per day for equity-accounted entities.

[d] Includes 9 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 131 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 131 million barrels in Russia.

Movements in estimated net proved reserves – continued

Total liquids[a b]										million barrels 2017
	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	168	—	1,051	42	14	330	—	1,107	42	2,753
Undeveloped	277	—	569	209	39	43	—	245	16	1,398
	445	—	1,621	251	53	372	—	1,352	57	4,151
Changes attributable to										
Revisions of previous estimates	17	—	164	5	1	45	—	407	(2)	637
Improved recovery	—	—	27	—	—	2	—	—	—	29
Purchases of reserves-in-place	3	—	1	—	—	1	—	—	—	5
Discoveries and extensions	—	—	12	—	—	—	—	42	—	54
Production[d]	(32)	—	(155)	(7)	(8)	(92)	—	(119)	(7)	(419)
Sales of reserves-in-place	(10)	—	—	—	—	—	—	—	—	(10)
	(22)	—	49	(2)	(7)	(43)	—	330	(9)	296
At 31 December[e]										
Developed	256	—	1,108	54	12	301	—	1,040	36	2,808
Undeveloped	167	—	561	195	34	28	—	642	12	1,639
	424	—	1,669	248	46	329	—	1,682	48	4,447
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	48	—	—	321	12	3,213	43	—	3,637
Undeveloped	—	71	—	—	325	—	2,148	1	—	2,545
	—	119	—	—	646	12	5,361	44	—	6,183
Changes attributable to										
Revisions of previous estimates	—	2	—	—	1	1	170	(1)	—	174
Improved recovery	—	13	—	—	4	—	—	—	—	17
Purchases of reserves-in-place	—	36	—	—	—	—	37	—	—	72
Discoveries and extensions	—	1	—	—	22	—	264	—	—	288
Production	—	(12)	—	—	(28)	(2)	(327)	(36)	—	(405)
Sales of reserves-in-place	—	(6)	—	—	(98)	—	—	—	—	(104)
	—	34	—	—	(98)	(1)	144	(37)	—	43
At 31 December[g h]										
Developed	—	60	—	—	285	11	3,206	6	—	3,569
Undeveloped	—	93	—	—	263	—	2,300	—	—	2,656
	—	153	—	—	548	12	5,505	6	—	6,225
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	168	48	1,051	42	335	342	3,213	1,150	42	6,390
Undeveloped	277	71	569	209	364	43	2,148	246	16	3,943
	445	119	1,621	251	699	385	5,361	1,395	57	10,333
At 31 December										
Developed	256	60	1,108	54	297	313	3,206	1,047	36	6,377
Undeveloped	167	93	561	195	297	28	2,300	642	12	4,295
	424	153	1,669	249	594	341	5,505	1,688	48	10,672

[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 9 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 2 thousand barrels per day for equity-accounted entities.

[e] Also includes 14 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 338 million barrels in respect of the non-controlling interest in Rosneft, including 6 mmboe held through BP's equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[i] Total proved liquid reserves held as part of our equity interest in Rosneft is 5,533 million barrels, comprising less than 1 million barrels in Canada, 59 million barrels in Venezuela, less than 1 million barrels in Vietnam and 5,473 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
										billion cubic feet 2017
Subsidiaries										
At 1 January										
Developed	499	—	5,447	—	1,784	767	—	1,890	3,012	13,398
Undeveloped	350	—	2,567	—	4,970	2,191	—	3,769	1,643	15,490
	848	—	8,014	—	6,755	2,958	—	5,659	4,654	28,888
Changes attributable to										
Revisions of previous estimates	50	—	(38)	3	(677)	(450)	—	258	(129)	(983)
Improved recovery	—	—	1,002	—	—	1	—	6	—	1,009
Purchases of reserves-in-place	25	—	—	—	—	527	—	—	—	552
Discoveries and extensions	—	—	10	—	829	14	—	1,229	—	2,082
Production[c]	(77)	—	(664)	(3)	(714)	(380)	—	(152)	(291)	(2,281)
Sales of reserves-in-place	(4)	—	—	—	—	—	—	—	—	(4)
	(5)	—	309	—	(562)	(288)	—	1,342	(420)	376
At 31 December[d]										
Developed	523	—	5,238	(1)	2,862	1,159	—	2,755	2,730	15,266
Undeveloped	320	—	3,086	—	3,330	1,510	—	4,245	1,505	13,997
	843	—	8,323	(1)	6,193	2,670	—	7,000	4,235	29,263
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	89	—	—	1,546	412	5,544	26	—	7,617
Undeveloped	—	21	—	—	534	—	6,304	4	—	6,863
	—	110	—	1	2,080	412	11,847	30	—	14,480
Changes attributable to										
Revisions of previous estimates	—	19	—	—	47	5	1,556	(2)	—	1,625
Improved recovery	—	37	—	—	55	—	—	—	—	92
Purchases of reserves-in-place	—	39	—	—	—	237	10	—	—	286
Discoveries and extensions	—	1	—	—	67	—	324	—	—	392
Production[c]	—	(19)	—	—	(178)	(32)	(488)	(8)	—	(726)
Sales of reserves-in-place	—	(6)	—	—	(347)	—	—	—	—	(353)
	—	70	—	—	(356)	210	1,403	(10)	—	1,316
At 31 December[f g]										
Developed	—	112	—	—	1,274	476	6,077	17	—	7,955
Undeveloped	—	69	—	—	450	146	7,173	3	—	7,841
	—	180	—	—	1,724	622	13,250	20	—	15,796
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	499	89	5,447	—	3,330	1,179	5,544	1,916	3,012	21,015
Undeveloped	350	21	2,567	—	5,505	2,191	6,304	3,772	1,643	22,353
	848	110	8,014	—	8,835	3,370	11,847	5,688	4,654	43,368
At 31 December										
Developed	523	112	5,238	—	4,136	1,635	6,077	2,771	2,730	23,221
Undeveloped	320	69	3,086	—	3,781	1,656	7,173	4,249	1,505	21,838
	843	180	8,323	—	7,917	3,291	13,250	7,020	4,235	45,060

[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, 131 billion cubic feet in subsidiaries, 49 billion cubic feet in equity-accounted entities.

[d] Includes 1,860 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 306 billion cubic feet of natural gas in respect of the 2.30% non-controlling interest in Rosneft including 2 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 13,522 billion cubic feet, comprising 0 billion cubic feet in Canada, 28 billion cubic feet in Venezuela, 19 billion cubic feet in Vietnam, 237 billion cubic feet in Egypt and 13,237 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

Total hydrocarbons[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
										million barrels of oil equivalent[c] 2017
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	254	—	1,990	42	321	462	—	1,433	561	5,063
Undeveloped	338	—	1,012	209	896	420	—	895	299	4,068
	592	—	3,002	251	1,217	882	—	2,327	860	9,131
Changes attributable to										
Revisions of previous estimates	25	—	157	5	(116)	(32)	—	451	(24)	467
Improved recovery	—	—	200	—	—	2	—	1	—	203
Purchases of reserves-in-place	8	—	1	—	—	92	—	—	—	100
Discoveries and extensions	—	—	14	—	143	3	—	254	—	413
Production[e f]	(45)	—	(270)	(8)	(131)	(157)	—	(145)	(57)	(812)
Sales of reserves-in-place	(11)	—	—	—	—	—	—	—	—	(11)
	(23)	—	102	(2)	(104)	(93)	—	562	(81)	361
At 31 December[g]										
Developed	347	—	2,011	54	505	501	—	1,515	507	5,440
Undeveloped	222	—	1,093	195	608	288	—	1,374	272	4,052
	569	—	3,104	248	1,114	790	—	2,889	779	9,492
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed	—	63	—	—	588	83	4,168	47	—	4,951
Undeveloped	—	75	—	—	417	—	3,235	1	—	3,729
	—	138	—	—	1,005	83	7,404	49	—	8,679
Changes attributable to										
Revisions of previous estimates	—	5	—	—	9	2	439	(1)	—	454
Improved recovery	—	19	—	—	14	—	—	—	—	33
Purchases of reserves-in-place	—	42	—	—	—	41	38	—	—	122
Discoveries and extensions	—	1	—	—	34	—	320	—	—	355
Production[e]	—	(15)	—	—	(58)	(7)	(411)	(38)	—	(530)
Sales of reserves-in-place	—	(7)	—	—	(158)	—	—	—	—	(165)
	—	46	—	—	(159)	35	386	(39)	—	269
At 31 December[i j]										
Developed	—	80	—	—	505	93	4,254	9	—	4,941
Undeveloped	—	105	—	—	341	25	3,536	1	—	4,008
	—	184	—	—	846	119	7,790	10	—	8,949
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	254	63	1,990	42	909	545	4,168	1,480	561	10,014
Undeveloped	338	75	1,012	209	1,313	420	3,235	896	299	7,797
	592	138	3,002	251	2,222	966	7,404	2,376	860	17,810
At 31 December										
Developed	347	80	2,011	54	1,010	595	4,254	1,524	507	10,381
Undeveloped	222	105	1,093	195	949	314	3,536	1,374	272	8,060
	569	184	3,104	249	1,959	908	7,790	2,899	779	18,441

[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 9 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 2 thousand barrels per day for equity-accounted entities.

[f] Includes 31 million barrels of oil equivalent of natural gas consumed in operations, 23 million barrels of oil equivalent in subsidiaries, 8 million barrels of oil equivalent in equity-accounted entities.

[g] Includes 335 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 391 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 7 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 7,864 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada, 64 million barrels of oil equivalent in Venezuela, 3 million barrels of oil equivalent in Vietnam, 41 million barrels of oil equivalent in Egypt and 7,755 million barrels of oil equivalent in Russia.

Movements in estimated net proved reserves – continued

Crude oil[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia[d]		million barrels 2016
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates[d]	13	—	(30)	—	(2)	22	—	543	2	548
Improved recovery	—	—	1	—	—	3	—	70	—	74
Purchases of reserves-in-place	3	—	3	—	—	—	—	25	1	32
Discoveries and extensions	2	—	—	4	—	—	—	—	—	6
Production[e]	(29)	(9)	(119)	(5)	(4)	(96)	—	(75)	(6)	(341)
Sales of reserves-in-place	—	(97)	(1)	—	—	—	—	(1)	(2)	(102)
	(11)	(106)	(145)	(1)	(6)	(71)	—	562	(5)	218
At 31 December[f]										
Developed	155	—	826	42	9	317	—	1,107	32	2,487
Undeveloped	274	—	497	209	11	42	—	245	14	1,291
	429	—	1,322	251	20	358	—	1,352	46	3,778
Equity-accounted entities (BP share)[g]										
At 1 January										
Developed	—	—	—	—	311	2	2,844	68	—	3,225
Undeveloped	—	—	—	—	311	—	1,981	—	—	2,292
	—	—	—	—	622	2	4,825	68	—	5,517
Changes attributable to										
Revisions of previous estimates	—	—	—	—	(2)	—	33	13	—	45
Improved recovery	—	—	—	—	1	—	4	—	—	5
Purchases of reserves-in-place	—	116	—	—	36	—	456	—	—	609
Discoveries and extensions	—	—	—	—	16	—	285	—	—	301
Production	—	(3)	—	—	(28)	—	(305)	(37)	—	(373)
Sales of reserves-in-place	—	—	—	—	—	—	(2)	(1)	—	(2)
	—	114	—	—	24	—	471	(25)	—	584
At 31 December[h]										
Developed	—	45	—	—	321	1	3,162	43	—	3,573
Undeveloped	—	69	—	—	325	—	2,134	1	—	2,529
	—	114	—	—	646	1	5,296	44	—	6,101
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	155	45	826	42	330	318	3,162	1,150	32	6,060
Undeveloped	274	69	497	209	336	42	2,134	246	14	3,819
	429	114	1,322	251	666	360	5,296	1,395	46	9,879

[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 9 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] Rest of Asia includes additions from Abu Dhabi ADCO concession.

[e] Includes 6 million barrels of crude oil 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 347 million barrels of crude oil in respect of the 6.58% non-controlling interest in Rosneft, including 6 mmbbl held through BP's equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[h] Total proved crude oil reserves held as part of our equity interest in Rosneft is 5,330 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 62 million barrels in Venezuela and 5,268 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas liquids[a b]										million barrels 2016
	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	5	11	269	—	7	5	—	—	9	308
Undeveloped	4	1	70	—	28	10	—	—	2	115
	10	12	339	—	35	15	—	—	12	422
Changes attributable to										
Revisions of previous estimates	7	—	(24)	—	—	1	—	—	—	(14)
Improved recovery	—	—	3	—	—	—	—	—	—	3
Purchases of reserves-in-place	1	—	4	—	—	—	—	—	—	6
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production[c]	(2)	(1)	(24)	—	(2)	(2)	—	—	(1)	(34)
Sales of reserves-in-place	—	(10)	—	—	—	—	—	—	—	(10)
	7	(12)	(40)	—	(2)	(1)	—	—	(1)	(49)
At 31 December[d]										
Developed	13	—	226	—	5	13	—	—	9	266
Undeveloped	3	—	73	—	28	1	—	—	2	107
	16	—	299	—	33	14	—	—	11	373
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	—	—	—	—	13	32	—	—	45
Undeveloped	—	—	—	—	—	—	15	—	—	15
	—	—	—	—	—	13	47	—	—	60
Changes attributable to										
Revisions of previous estimates	—	—	—	—	—	(2)	18	—	—	16
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases of reserves-in-place	—	5	—	—	—	—	—	—	—	5
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	5	—	—	—	(2)	18	—	—	21
At 31 December[f]										
Developed	—	3	—	—	—	11	50	—	—	65
Undeveloped	—	2	—	—	—	—	15	—	—	17
	—	5	—	—	—	11	65	—	—	81
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	13	3	226	—	5	24	50	—	9	331
Undeveloped	3	2	73	—	28	1	15	—	2	123
	16	5	299	—	33	25	65	—	11	454

[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 3 thousand barrels per day for equity-accounted entities.

[d] Includes 10 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 65 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 65 million barrels in Russia.

Movements in estimated net proved reserves – continued

Total liquids[a b]										million barrels 2016
	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	147	98	1,159	46	15	346	—	598	45	2,453
Undeveloped	303	20	647	205	46	99	—	192	18	1,529
	449	117	1,806	252	61	444	—	790	63	3,982
Changes attributable to										
Revisions of previous estimates[d]	20	—	(54)	—	(2)	23	—	543	3	533
Improved recovery	—	—	5	—	—	3	—	70	—	78
Purchases of reserves-in-place	5	—	7	—	—	—	—	25	1	38
Discoveries and extensions	2	—	—	4	—	—	—	—	—	6
Production[e]	(31)	(10)	(143)	(5)	(6)	(98)	—	(75)	(7)	(375)
Sales of reserves-in-place	—	(108)	(1)	—	—	—	—	(1)	(2)	(112)
	(4)	(117)	(185)	(1)	(8)	(72)	—	562	(5)	168
At 31 December[f]										
Developed	168	—	1,051	42	14	330	—	1,107	42	2,753
Undeveloped	277	—	569	209	39	43	—	245	16	1,398
	445	—	1,621	251	53	372	—	1,352	57	4,151
Equity-accounted entities (BP share)[g]										
At 1 January										
Developed	—	—	—	—	311	14	2,876	68	—	3,270
Undeveloped	—	—	—	—	312	—	1,996	—	—	2,307
	—	—	—	—	622	14	4,872	68	—	5,577
Changes attributable to										
Revisions of previous estimates	—	—	—	—	(2)	(2)	51	13	—	61
Improved recovery	—	—	—	—	1	—	4	—	—	5
Purchases of reserves-in-place	—	122	—	—	36	—	456	—	—	614
Discoveries and extensions	—	—	—	—	16	—	285	—	—	301
Production	—	(3)	—	—	(28)	—	(305)	(37)	—	(374)
Sales of reserves-in-place	—	—	—	—	—	—	(2)	(1)	—	(2)
	—	119	—	—	24	(2)	489	(25)	—	605
At 31 December[h i]										
Developed	—	48	—	—	321	12	3,213	43	—	3,637
Undeveloped	—	71	—	—	325	—	2,148	1	—	2,545
	—	119	—	—	646	12	5,361	44	—	6,183
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	168	48	1,051	42	335	342	3,213	1,150	42	6,390
Undeveloped	277	71	569	209	364	43	2,148	246	16	3,943
	445	119	1,621	251	699	385	5,361	1,395	57	10,333

[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 9 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] Rest of Asia includes additions from Abu Dhabi ADCO concession.

[e] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 3 thousand barrels per day for equity-accounted entities.

[f] Also includes 16 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[h] Includes 347 million barrels in respect of the non-controlling interest in Rosneft, including 6 mmboe held through BP's equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[i] Total proved liquid reserves held as part of our equity interest in Rosneft is 5,395 million barrels, comprising less than 1 million barrels in Canada, 62 million barrels in Venezuela, less than 1 million barrels in Vietnam and 5,333 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas[a b]										billion cubic feet 2016
	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	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
Changes attributable to										
Revisions of previous estimates	133	—	(231)	3	(1,042)	(19)	—	548	396	(211)
Improved recovery	—	—	469	—	42	1	—	22	—	534
Purchases of reserves-in-place	95	—	91	—	—	—	—	—	252	438
Discoveries and extensions	—	—	1	—	355	43	—	—	—	399
Production[c]	(71)	(33)	(676)	(4)	(624)	(219)	—	(152)	(306)	(2,085)
Sales of reserves-in-place	—	(256)	(2)	—	(37)	—	—	(17)	(439)	(750)
	158	(288)	(348)	—	(1,306)	(194)	—	401	(97)	(1,675)
At 31 December[d]										
Developed	499	—	5,447	—	1,784	767	—	1,890	3,012	13,398
Undeveloped	350	—	2,567	—	4,970	2,191	—	3,769	1,643	15,490
	848	—	8,014	—	6,755	2,958	—	5,659	4,654	28,888
Equity-accounted entities (BP share)[e]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	—	—	—	62	34	736	5	—	836
Improved recovery	—	—	—	—	1	—	10	—	—	11
Purchases of reserves-in-place	—	115	—	—	19	—	81	—	—	216
Discoveries and extensions	—	—	—	—	128	—	343	—	—	471
Production[c]	—	(4)	—	—	(190)	(8)	(461)	(15)	—	(680)
Sales of reserves-in-place	—	—	—	—	—	—	(1)	(8)	—	(8)
	—	110	—	—	20	26	709	(18)	—	846
At 31 December[f g]										
Developed	—	89	—	—	1,546	412	5,544	26	—	7,617
Undeveloped	—	21	—	—	534	—	6,304	4	—	6,863
	—	110	—	1	2,080	412	11,847	30	—	14,480
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	499	89	5,447	—	3,330	1,179	5,544	1,916	3,012	21,015
Undeveloped	350	21	2,567	—	5,505	2,191	6,304	3,772	1,643	22,353
	848	110	8,014	—	8,835	3,370	11,847	5,688	4,654	43,368

[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 176 billion cubic feet of natural gas consumed in operations, 145 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities.

[d] Includes 2,026 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 300 billion cubic feet of natural gas in respect of the 2.53% non-controlling interest in Rosneft including 1 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 11,900 billion cubic feet, comprising 1 billion cubic feet in Canada, 33 billion cubic feet in Venezuela, 23 billion cubic feet in Vietnam and 11,843 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

Total hydrocarbons[a b]									million barrels of oil equivalent[c] 2016	
	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	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
Changes attributable to										
Revisions of previous estimates[e]	43	—	(94)	1	(181)	20	—	637	71	497
Improved recovery	—	—	86	—	7	3	—	74	—	170
Purchases of reserves-in-place	21	—	23	—	—	—	—	25	44	113
Discoveries and extensions	2	—	—	4	61	8	—	—	—	75
Production[f g]	(43)	(16)	(260)	(5)	(114)	(136)	—	(101)	(60)	(735)
Sales of reserves-in-place	—	(152)	(1)	—	(7)	—	—	(4)	(78)	(241)
	23	(167)	(245)	(1)	(233)	(105)	—	631	(22)	(121)
At 31 December[h]										
Developed	254	—	1,990	42	321	462	—	1,433	561	5,063
Undeveloped	338	—	1,012	209	896	420	—	895	299	4,068
	592	—	3,002	251	1,217	882	—	2,327	860	9,131
Equity-accounted entities (BP share)[i]										
At 1 January										
Developed	—	—	—	—	563	81	3,732	76	—	4,452
Undeveloped	—	—	—	—	415	—	3,061	1	—	3,476
	—	—	—	—	978	81	6,792	77	—	7,928
Changes attributable to										
Revisions of previous estimates	—	—	—	—	9	4	178	14	—	205
Improved recovery	—	—	—	—	1	—	6	—	—	7
Purchases of reserves-in-place	—	142	—	—	39	—	470	—	—	652
Discoveries and extensions	—	—	—	—	38	—	344	—	—	382
Production[g]	—	(3)	—	—	(61)	(2)	(385)	(40)	—	(491)
Sales of reserves-in-place	—	—	—	—	—	—	(2)	(2)	—	(4)
	—	138	—	—	27	2	611	(28)	—	751
At 31 December[j k]										
Developed	—	63	—	—	588	83	4,168	47	—	4,951
Undeveloped	—	75	—	—	417	—	3,235	1	—	3,729
	—	138	—	—	1,005	83	7,404	49	—	8,679
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	254	63	1,990	42	909	545	4,168	1,480	561	10,014
Undeveloped	338	75	1,012	209	1,313	420	3,235	896	299	7,797
	592	138	3,002	251	2,222	966	7,404	2,376	860	17,810

[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 9 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] Rest of Asia includes additions from Abu Dhabi ADCO concession.

[f] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 3 thousand barrels per day for equity-accounted entities.

[g] 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.

[h] Includes 366 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[j] Includes 402 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 6 mmboe held through BP's equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[k] Total proved reserves held as part of our equity interest in Rosneft is 7,447 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada, 68 million barrels of oil equivalent in Venezuela, 4 million barrels of oil equivalent in Vietnam and 7,375 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
										2018
	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]	**39,700**	**—**	**160,000**	**4,100**	**17,500**	**30,400**	**—**	**147,500**	**30,000**	**429,200**
Future production cost[b]	**15,000**	**—**	**57,600**	**3,400**	**7,200**	**8,500**	**—**	**55,800**	**7,600**	**155,100**
Future development cost[b]	**2,100**	**—**	**17,800**	**1,100**	**2,800**	**2,600**	**—**	**16,400**	**2,500**	**45,300**
Future taxation[c]	**8,900**	**—**	**16,600**	**—**	**3,200**	**5,300**	**—**	**51,100**	**6,900**	**92,000**
Future net cash flows	**13,700**	**—**	**68,000**	**(400)**	**4,300**	**14,000**	**—**	**24,200**	**13,000**	**136,800**
10% annual discount[d]	**5,000**	**—**	**29,900**	**(200)**	**700**	**3,300**	**—**	**9,400**	**5,800**	**53,900**
Standardized measure of discounted future net cash flows[e f]	**8,700**	**—**	**38,100**	**(200)**	**3,600**	**10,700**	**—**	**14,800**	**7,200**	**82,900**
Equity-accounted entities (BP share)[g]										
Future cash inflows[a]	**—**	**12,800**	**—**	**—**	**38,500**	**—**	**356,800**	**—**	**—**	**408,100**
Future production cost[b]	**—**	**4,200**	**—**	**—**	**16,100**	**—**	**232,100**	**—**	**—**	**252,400**
Future development cost[b]	**—**	**800**	**—**	**—**	**3,600**	**—**	**19,300**	**—**	**—**	**23,700**
Future taxation[c]	**—**	**5,900**	**—**	**—**	**4,400**	**—**	**24,000**	**—**	**—**	**34,300**
Future net cash flows	**—**	**1,900**	**—**	**—**	**14,400**	**—**	**81,400**	**—**	**—**	**97,700**
10% annual discount[d]	**—**	**600**	**—**	**—**	**8,500**	**—**	**48,100**	**—**	**—**	**57,200**
Standardized measure of discounted future net cash flows[h i]	**—**	**1,300**	**—**	**—**	**5,900**	**—**	**33,300**	**—**	**—**	**40,500**
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	**8,700**	**1,300**	**38,100**	**(200)**	**9,500**	**10,700**	**33,300**	**14,800**	**7,200**	**123,400**

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	**(18,800)**	**(8,000)**	**(26,800)**
Development costs for the current year as estimated in previous year	**8,500**	**4,300**	**12,800**
Extensions, discoveries and improved recovery, less related costs	**5,800**	**3,500**	**9,300**
Net changes in prices and production cost	**41,000**	**15,800**	**56,800**
Revisions of previous reserves estimates	**(2,100)**	**2,100**	**—**
Net change in taxation	**(17,000)**	**(7,600)**	**(24,600)**
Future development costs	**1,000**	**(3,500)**	**(2,500)**
Net change in purchase and sales of reserves-in-place	**7,600**	**400**	**8,000**
Addition of 10% annual discount	**5,200**	**3,100**	**8,300**
Total change in the standardized measure during the year[j]	**31,200**	**10,100**	**41,300**

[a] The marker prices used were Brent $71.43/bbl, Henry Hub $3.10/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 with reference to 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] In certain situations, revenues and costs are included in the standardized measure of discounted future net cash flows valuation and excluded from the determination of proved reserves and vice versa. This can result in the standardized measure of discounted future net cash flows being negative.

[f] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $1,100 million.

[g] 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.

[h] Non-controlling interests in Rosneft amounted to $2,500 million in Russia.

[i] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.

[j] 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 changes to US dollars are included within 'Net changes in prices and production cost'.

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

$ million

2017

	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]	26,300	—	99,200	7,100	15,200	27,000	—	118,800	26,200	319,800
Future production cost[b]	13,800	—	46,700	4,100	7,100	8,600	—	52,600	8,400	141,300
Future development cost[b]	1,700	—	12,100	1,100	2,400	3,400	—	18,200	3,200	42,100
Future taxation[c]	4,200	—	6,500	—	1,700	3,800	—	33,200	4,800	54,200
Future net cash flows	6,600	—	33,900	1,900	4,000	11,200	—	14,800	9,800	82,200
10% annual discount[d]	2,100	—	13,100	1,100	500	3,400	—	5,500	4,800	30,500
Standardized measure of discounted future net cash flows[e]	4,500	—	20,800	800	3,500	7,800	—	9,300	5,000	51,700
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	—	9,000	—	—	32,900	—	205,100	400	—	247,400
Future production cost[b]	—	4,100	—	—	15,500	—	114,900	300	—	134,800
Future development cost[b]	—	800	—	—	3,400	—	17,600	100	—	21,900
Future taxation[c]	—	3,100	—	—	3,100	—	12,400	—	—	18,600
Future net cash flows	—	1,000	—	—	10,900	—	60,200	—	—	72,100
10% annual discount[d]	—	400	—	—	6,400	—	34,900	—	—	41,700
Standardized measure of discounted future net cash flows[g h]	—	600	—	—	4,500	—	25,300	—	—	30,400
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	4,500	600	20,800	800	8,000	7,800	25,300	9,300	5,000	82,100

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	(12,800)	(5,500)	(18,300)
Development costs for the current year as estimated in previous year	9,800	4,200	14,000
Extensions, discoveries and improved recovery, less related costs	2,300	1,300	3,600
Net changes in prices and production cost	33,100	7,300	40,400
Revisions of previous reserves estimates	2,800	1,000	3,800
Net change in taxation	(12,500)	(1,500)	(14,000)
Future development costs	3,000	(4,600)	(1,600)
Net change in purchase and sales of reserves-in-place	800	(600)	200
Addition of 10% annual discount	2,300	2,600	4,900
Total change in the standardized measure during the year[i]	28,800	4,200	33,000

[a] The marker prices used were Brent $54.36/bbl, Henry Hub $2.96/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 with reference to 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 $1,100 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 $1,963 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 changes to US dollars are included within 'Net changes in prices and production cost'.

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

										$ million
										2016
	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]	21,600	—	72,400	4,500	11,700	23,600	—	78,100	24,000	235,900
Future production cost[b]	13,900	—	43,100	3,500	6,600	10,000	—	42,600	9,400	129,100
Future development cost[b]	3,000	—	14,300	1,100	3,700	5,100	—	15,400	3,500	46,100
Future taxation[c]	1,700	—	500	—	100	2,000	—	17,800	3,400	25,500
Future net cash flows	3,000	—	14,500	(100)	1,300	6,500	—	2,300	7,700	35,200
10% annual discount[d e]	900	—	4,900	—	200	2,800	—	(600)	4,100	12,300
Standardized measure of discounted future net cash flows[e f]	2,100	—	9,600	(100)	1,100	3,700	—	2,900	3,600	22,900
Equity-accounted entities (BP share)[g]										
Future cash inflows[a]	—	5,400	—	—	34,400	—	159,900	1,900	—	201,600
Future production cost[b]	—	3,000	—	—	16,500	—	84,300	1,200	—	105,000
Future development cost[b]	—	700	—	—	3,800	—	13,200	700	—	18,400
Future taxation[c]	—	1,300	—	—	3,600	—	10,100	—	—	15,000
Future net cash flows	—	400	—	—	10,500	—	52,300	—	—	63,200
10% annual discount[d]	—	200	—	—	6,100	—	30,700	—	—	37,000
Standardized measure of discounted future net cash flows[h i]	—	200	—	—	4,400	—	21,600	—	—	26,200
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	2,100	200	9,600	(100)	5,500	3,700	21,600	2,900	3,600	49,100

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	(15,200)	(5,400)	(20,600)
Development costs for the current year as estimated in previous year	13,100	3,500	16,600
Extensions, discoveries and improved recovery, less related costs	700	900	1,600
Net changes in prices and production cost	(25,500)	(5,900)	(31,400)
Revisions of previous reserves estimates	12,200	1,200	13,400
Net change in taxation	(2,500)	900	(1,600)
Future development costs	4,900	(2,500)	2,400
Net change in purchase and sales of reserves-in-place	1,800	2,900	4,700
Addition of 10% annual discount	3,000	2,800	5,800
Total change in the standardized measure during the year[j]	(7,500)	(1,600)	(9,100)

[a] The marker prices used were Brent $42.82/bbl, Henry Hub $2.46/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 with reference to 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] In certain situations, revenues and costs are included in the standardized measure of discounted future net cash flows valuation and excluded from the determination of proved reserves and vice versa. This can result in the standardized measure of discounted future net cash flows being negative. Depending on the timing of those cash flows the effect of discounting may be to increase the discounted future net cash flows.

[f] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $300 million.

[g] 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.

[h] Non-controlling interests in Rosneft amounted to $1,608 million in Russia.

[i] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.

[j] 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'.

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 2018, 2017 and 2016.

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[d]		
Subsidiaries[e]										
Crude oil[f]										thousand barrels per day
2018	**101**	**—**	**385**	**24**	**7**	**204**	**—**	**313**	**17**	**1,051**
2017	80	—	370	20	12	241	—	325	17	1,064
2016	79	24	335	13	10	263	—	204	16	943
Natural gas liquids										thousand barrels per day
2018	**5**	**—**	**60**	**—**	**9**	**11**	**—**	**—**	**2**	**88**
2017	6	—	56	—	10	10	—	—	2	85
2016	6	4	56	—	8	5	—	—	3	82
Natural gas[g]										million cubic feet per day
2018	**152**	**—**	**1,900**	**7**	**2,136**	**1,061**	**—**	**826**	**819**	**6,900**
2017	182	—	1,659	9	1,936	949	—	371	783	5,889
2016	170	82	1,656	10	1,689	513	—	363	820	5,302
Equity-accounted entities (BP share)										
Crude oil[f]										thousand barrels per day
2018	**—**	**34**	**—**	**—**	**55**	**1**	**933**	**16**	**—**	**1,040**
2017	—	31	—	—	63	1	905	99	—	1,099
2016	—	7	—	—	65	—	840	102	—	1,015
Natural gas liquids										thousand barrels per day
2018	**—**	**2**	**—**	**—**	**—**	**6**	**4**	**—**	**—**	**12**
2017	—	2	—	—	—	6	4	—	—	12
2016	—	—	—	—	1	4	4	—	—	8
Natural gas[g]										million cubic feet per day
2018	**—**	**59**	**—**	**—**	**335**	**80**	**1,286**	**—**	**—**	**1,760**
2017	—	53	—	—	418	77	1,308	—	—	1,855
2016	—	12	—	—	449	18	1,279	15	—	1,773

[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] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods.

[e] All of the oil and liquid production from Canada is bitumen.

[f] Crude oil includes condensate.

[g] 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 2018. 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 2018											
Oil wells[c]	– gross	**116**	**74**	**2,677**	**169**	**5,356**	**695**	**66,147**	**1,979**	**12**	**77,225**
	– net	**69**	**22**	**1,097**	**45**	**2,437**	**466**	**13,151**	**445**	**2**	**17,734**
Gas wells[d]	– gross	**34**	**1**	**20,565**	**244**	**1,069**	**209**	**512**	**102**	**78**	**22,814**
	– net	**5**	**—**	**10,602**	**121**	**379**	**89**	**114**	**45**	**16**	**11,371**
Oil and natural gas acreage at 31 December 2018											thousands of acres
Developed	– gross	**81**	**57**	**6,263**	**147**	**1,336**	**868**	**6,751**	**1,290**	**173**	**16,966**
	– net	**46**	**17**	**3,683**	**64**	**355**	**345**	**1,297**	**272**	**41**	**6,120**
Undeveloped[e]	– gross	**3,067**	**180**	**5,012**	**17,110**	**19,890**	**52,698**	**431,130**	**8,586**	**4,022**	**541,695**
	– net	**1,861**	**54**	**3,700**	**8,750**	**6,469**	**36,504**	**86,045**	**2,357**	**1,889**	**147,629**

[a] Based on information received from Rosneft as at 31 December 2018.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Includes approximately 7,381 gross (1,447 net) multiple completion wells (more than one formation producing into the same well bore).
[d] Includes approximately 2,768 gross (1,407 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.

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		
2018										
Exploratory										
Productive	**0.3**	**—**	**1.7**	**—**	**2.0**	**—**	**15.0**	**5.0**	**—**	**24.0**
Dry	**—**	**—**	**—**	**0.5**	**2.0**	**2.4**	**—**	**—**	**—**	**4.9**
Development										
Productive	**1.4**	**0.6**	**142.7**	**5.0**	**103.9**	**14.4**	**137.3**	**53.5**	**1.3**	**460.1**
Dry	**—**	**—**	**6.8**	**—**	**3.6**	**—**	**—**	**2.6**	**—**	**13.0**
2017										
Exploratory										
Productive	2.8	0.1	1.5	1.2	3.2	2.6	9.4	1.4	—	22.2
Dry	2.4	—	—	—	—	2.9	—	1.0	—	6.3
Development										
Productive	2.5	0.5	124.0	8.0	103.7	16.5	282.7	43.6	1.1	582.6
Dry	—	—	0.5	—	1.6	2.1	—	0.8	—	5.0
2016										
Exploratory										
Productive	0.3	0.4	0.5	—	0.6	2.1	3.4	1.6	—	8.9
Dry	1.0	0.3	4.7	—	—	1.5	—	0.3	—	7.8
Development										
Productive	3.4	1.4	145.6	—	99.8	20.2	88.5	55.2	0.5	414.6
Dry	0.8	—	—	—	0.6	2.0	—	1.0	—	4.4

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

Operational and statistical information – continued

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 2018. 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 2018										
Exploratory										
Gross	**—**	**0.9**	**5.0**	**—**	**3.0**	**3.0**	**—**	**3.0**	**—**	**14.9**
Net	**—**	**0.3**	**2.9**	**—**	**0.8**	**1.3**	**—**	**3.0**	**—**	**8.3**
Development										
Gross	**9.0**	**4.6**	**147.0**	**5.0**	**11.0**	**18.0**	**—**	**108.0**	**—**	**302.6**
Net	**2.9**	**1.4**	**80.5**	**2.5**	**5.0**	**9.2**	**—**	**19.0**	**—**	**120.5**

[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	Note	2018	$ million 2017
Non-current assets			
Investments	2	**166,271**	166,276
Receivables	3	**2,600**	2,623
Defined benefit pension plan surpluses	4	**5,473**	3,838
		174,344	172,737
Current assets			
Receivables	3	**151**	293
Cash and cash equivalents		**13**	10
		164	303
Total assets		**174,508**	173,040
Current liabilities			
Payables[a]	5	**14,665**	10,203
Non-current liabilities			
Payables[a]	5	**31,800**	31,804
Deferred tax liabilities	6	**1,907**	1,337
Defined benefit pension plan deficits	4	**184**	221
		33,891	33,362
Total liabilities		**48,556**	43,565
Net assets		**125,952**	129,475
Capital and reserves[b]			
Profit and loss account			
Brought forward		**101,078**	104,498
Profit (loss) for the year		**1,931**	2,145
Other movements		**(6,579)**	(5,565)
		96,430	101,078
Called-up share capital	7	**5,402**	5,343
Share premium account		**12,305**	12,147
Other capital and reserves		**11,815**	10,907
		125,952	129,475

[a] A re-presentation from non-current payables to current payables has been made in 2017. See Note 5 for details.

[b] See Statement of changes in equity on page 239 for further information.

The financial statements on pages 238-271 were approved and signed by the group chief executive on 29 March 2019 having been duly authorized to do so by the board of directors:

R W Dudley Group chief executive

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

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 2018	**5,343**	**12,147**	**1,426**	**26,509**	**(16,958)**	**(70)**	**101,078**	**129,475**
Profit for the year	**—**	**—**	**—**	**—**	**—**	**—**	**1,931**	**1,931**
Other comprehensive income	**—**	**—**	**—**	**—**	**—**	**(296)**	**1,178**	**882**
Total comprehensive income	**—**	**—**	**—**	**—**	**—**	**(296)**	**3,109**	**2,813**
Dividends	**49**	**(49)**	**—**	**—**	**—**	**—**	**(6,699)**	**(6,699)**
Repurchases of ordinary share capital	**(13)**	**—**	**13**	**—**	**—**	**—**	**(355)**	**(355)**
Share-based payments, net of tax	**23**	**207**	**—**	**—**	**1,191**	**—**	**(703)**	**718**
At 31 December 2018	**5,402**	**12,305**	**1,439**	**26,509**	**(15,767)**	**(366)**	**96,430**	**125,952**
At 1 January 2017	5,284	12,219	1,413	26,509	(18,443)	(236)	104,498	131,244
Profit for the year	—	—	—	—	—	—	2,145	2,145
Other comprehensive income	—	—	—	—	—	166	1,815	1,981
Total comprehensive income	—	—	—	—	—	166	3,960	4,126
Dividends	72	(72)	—	—	—	—	(6,153)	(6,153)
Repurchases of ordinary share capital	(13)	—	13	—	—	—	(343)	(343)
Share-based payments, net of tax	—	—	—	—	1,485	—	(884)	601
At 31 December 2017	5,343	12,147	1,426	26,509	(16,958)	(70)	101,078	129,475

[a] See Note 8 for further information.

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 2018 were approved and signed by the group chief executive on 29 March 2019 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 'Application of Financial Reporting Requirements' (FRS 100) issued by the Financial Reporting Council. Accordingly, these financial statements have been prepared in accordance with FRS 101 and in accordance with the provisions of the UK Companies Act 2006.

Basis of preparation

The financial statements have been 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 FRS 101, the company has taken advantage of the disclosure exemptions available in relation to:

(a) the requirements of IFRS 7 'Financial Instruments: Disclosures';

(b) the requirements of paragraphs 10(d), 10(f), 16, 38A, 38B, 38C, 38D, 40A, 40B, 40C, 40D, 111 and 134 to 136 of IAS 1 'Presentation of Financial Statements';

(c) the requirements of IAS 7 'Statement of Cash Flows';

(d) the requirements of paragraphs 30 and 31 of IAS 8 'Accounting Policies, Changes in Accounting Estimates and Errors' in relation to standards not yet effective;

(e) the requirements of paragraphs 17 and 18A of IAS 24 'Related Party Disclosures'; and

(f) the requirements of IAS 24 'Related Party Disclosures' to disclose related party transactions entered into between two or more members of a group, provided that any subsidiary which is a party to the transaction is wholly owned by such a member.

(g) the requirement of the second sentence of paragraph 110 and paragraphs 113(a), 114,115, 118, 119(a) to (c), 120 to 127 and 129 of IFRS 15 Revenue from Contracts with Customers

Where required, equivalent disclosures are given in the consolidated financial statements of BP p.l.c.

As permitted by Section 408 of the Companies Act 2006, the income statement 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), 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 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 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 amount 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. Where these circumstances have reversed, the impairment previously made is reversed to the extent of the original cost of the investment.

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 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. Non-monetary assets and liabilities, other than those measured at fair value, are not retranslated subsequent to initial recognition.

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 recognized in a separate component of equity and reported in other comprehensive income. Income statement transactions are translated into US dollars using the average exchange rate for the reporting period.

Financial guarantees

The company enters into financial guarantee contracts with its subsidiaries. At the inception of a financial guarantee contract, a liability is recognized initially at fair value and then subsequently at the higher of the estimated loss and amortized cost. Where a guarantee is issued for a premium, a receivable of an amount equal to the liability is initially recognized. Subsequently, the liability and receivable reduce by the amount of consideration received, which is recognized in the income statement. Where a guarantee is issued without a premium, the fair value is recognized as additional investment in the entity to which the guarantee relates.

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

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

Share-based payments

Equity-settled transactions

The cost of equity-settled transactions with employees of the company and other members of the group is measured by reference to the fair value of the equity instruments on the date on which they 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.

For other equity-settled share-based payment transactions, the goods or services received and the corresponding increase in equity are measured at the fair value of the goods or services received, unless their fair value cannot be reliably estimated. If the fair value of the goods and services received cannot be reliably estimated, the transaction is measured by reference to the fair value of the equity instruments granted.

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

The defined benefit pension plans are plans that share risks between entities under common control. In each instance BP p.l.c. is the principal employer and carries the whole plan surplus or deficit on its balance sheet. 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.

Net interest expense relating to pensions, 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 on 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: pensions

Accounting for defined benefit pensions involves making significant estimates when measuring the company's pension plan surpluses and deficits. These estimates require assumptions to be made about many uncertainties.

Pension 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 company's balance sheet, and pension expense for the following year. The assumptions used are provided in Note 4.

The assumptions that are the most significant to the amounts reported are the discount rate, inflation rate, salary growth and mortality levels. Assumptions about these variables are based on the environment in each country. The assumptions used vary from year to year, with resultant effects on future net income and net assets. Changes to some of these assumptions, in particular the discount rate and inflation rate, could result in material changes to the carrying amounts of the company's pension obligations within the next financial year for the UK plan. Any differences between these assumptions and the actual outcome will also affect future net income and net assets.

The values ascribed to these assumptions and a sensitivity analysis of the impact of changes in the assumptions on the benefit expense and obligation used are provided in Note 4.

Income taxes

Income tax expense represents the sum of current tax and deferred tax.

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.

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

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

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. See note 6 for further details.

Financial assets

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. The subsequent measurement of financial assets depends on their classification, as set out below. The company derecognizes financial assets when the contractual rights to the cash flows expire or the financial asset is transferred to a third party.

Financial assets measured at amortized cost

Financial assets are classified as measured at amortized cost when they are held in a business model the objective of which is to collect contractual cash flows and the contractual cash flows represent solely payments of principal and interest. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in profit or loss when the assets are derecognized or impaired and when interest is recognized using the effective interest method. This category of financial assets includes trade and other receivables.

Cash equivalents

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 generally have a maturity of three months or less from the date of acquisition. Cash equivalents are classified as financial assets measured at amortized cost.

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, net of directly attributable transaction costs. For interest-bearing loans and borrowings this is typically equivalent to 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 in interest and other income and finance costs respectively. This category of financial liabilities includes trade and other payables and finance debt.

Impact of new International Financial Reporting Standards

The company adopted two new accounting standards issued by the IASB with effect from 1 January 2018, IFRS 9 'Financial instruments' and IFRS 15 'Revenue from contracts with customers'. There are no other new or amended standards or interpretations adopted during the year that have a significant impact on the financial statements.

IFRS 9 'Financial Instruments'

IFRS 9 'Financial Instruments' was issued in July 2014 and replaced IAS 39 'Financial Instruments: Recognition and Measurement.' The company adopted IFRS 9 and the related consequential amendments to other IFRSs in the financial reporting period commencing 1 January 2018. The company has applied the new standard in accordance with the transition provisions of IFRS 9. Comparatives have not been restated and there were no material adjustments on transition reported in opening retained earnings at 1 January 2018.

The company's revised accounting policies in relation to financial instruments are provided above.

IFRS 15 'Revenue from Contracts with Customers'

IFRS 15 'Revenue from Contracts with Customers' was issued in May 2014 and replaced IAS 18 'Revenue' and certain other standards and interpretations. IFRS 15 provides a single model for accounting for revenue arising from contracts with customers, focusing on the identification and satisfaction of performance obligations. The company adopted IFRS 15 from 1 January 2018 and applied the 'modified retrospective' transition approach to implementation. The company identified no changes in accounting as a result of implementing IFRS 15.

2. Investments

			$ million
	Subsidiaries	**Associates**	
	Shares	**Shares**	**Total**
Cost			
At 1 January 2018	**166,307**	**2**	**166,309**
Additions	**270**	**—**	**270**
Disposals	**(275)**	**—**	**(275)**
At 31 December 2018	**166,302**	**2**	**166,304**
Amounts provided			
At 1 January 2018	**33**	**—**	**33**
At 31 December 2018	**33**	**—**	**33**
Cost			
At 1 January 2017	166,355	2	166,357
Disposals	(41)	—	(41)
Other movements	(7)	—	(7)
At 31 December 2017	166,307	2	166,309
Amounts provided			
At 1 January 2017	74	—	74
Disposals	(41)	—	(41)
At 31 December 2017	33	—	33
At 31 December 2018	**166,269**	**2**	**166,271**
At 31 December 2017	166,274	2	166,276

The more important subsidiaries of the company at 31 December 2018 and the percentage holding of ordinary share capital (to the nearest whole number) are set out below. For a full list of related undertakings see Note 14.

Subsidiaries	%	Country of incorporation	Principal activities
International			
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 the investment in BP International Limited at 31 December 2018 was $76,152 million (2017 $76,152 million).

3. Receivables

				$ million
		2018		2017
	Current	**Non-current**	Current	Non-current
Amounts receivable from subsidiaries[a]	**148**	**2,600**	289	2,623
Amounts receivable from associates	**4**	**—**	4	—
Other receivables	**(1)**	**—**	—	—
	151	**2,600**	293	2,623

[a] Non-current receivables includes a promissory note issued by BP (Abu Dhabi) Limited in 2016 in consideration for the issue of BP p.l.c. ordinary shares to the government of Abu Dhabi.

4. Pensions

The primary pension arrangement is a funded final salary pension plan in the UK 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, 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 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 2018 the aggregate level of contributions was $490 million (2017 $509 million). The aggregate level of contributions in 2019 is expected to be approximately $262 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.

4. Pensions – continued

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 is agreed covering the next five years. Contractually committed funding amounted to $1,275 million at 31 December 2018, all of which relates to future 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 2018. 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 2017.

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 benefits at 31 December and pension expense for the following year.

Financial assumptions used to determine benefit obligation		%
	2018	2017
Discount rate for pension plan liabilities	**2.9**	2.5
Rate of increase in salaries	**3.8**	4.1
Rate of increase for pensions in payment	**3.0**	2.9
Rate of increase in deferred pensions	**3.0**	2.9
Inflation for pension plan liabilities	**3.1**	3.1

Financial assumptions used to determine benefit expense		%
	2018	2017
Discount rate for pension plan service costs	**2.6**	2.7
Discount rate for pension plan other finance expense	**2.5**	2.7
Inflation for pension plan service costs	**3.1**	3.2

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 comprises of an allowance for promotion-related salary growth of 0.7%.

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
	2018	2017
Life expectancy at age 60 for a male currently aged 60	**27.4**	27.4
Life expectancy at age 60 for a male currently aged 40	**28.9**	29.0
Life expectancy at age 60 for a female currently aged 60	**28.8**	28.8
Life expectancy at age 60 for a female currently aged 40	**30.6**	30.5

The assets of the primary plan are held in a trust, the primary objective of which 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.

The trustee's long-term investment objective for the primary UK plan as it matures is to invest in assets whose value changes in the same way as the plan liabilities, in order to reduce the level of funding risk. To move towards this objective, the UK plan uses a liability driven investment (LDI) approach for part of the portfolio, investing primarily in government bonds to achieve this matching effect for the most significant plan liability assumptions of interest rate and inflation rate. This is partly funded by short-term sale and repurchase agreements, whereby the plan borrows money using existing bonds as security and which will be bought back at a specified price at an agreed future date. The funds raised are used to invest in further bonds to increase the proportion of assets which match the plan liabilities. The borrowings are shown separately in the analysis of pension plan assets in the table below.

For the primary UK pension plan there is an agreement with the trustee to increase the proportion of assets with liability matching characteristics over time primarily by reducing the proportion of plan assets held as equities and increasing the proportion held as bonds. During 2018, the plan switched 12.5% from equities to bonds.

The company's asset allocation policy for the primary plan is as follows:

Asset category	%
Total equity (including private equity)	**30**
Bonds/cash (including LDI)	**63**
Property/real estate	**7**

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2018 were $4,197 million (2017 $2,588 million) of government-issued nominal bonds and $17,491 million (2017 $16,177 million) of index-linked bonds.

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

4. Pensions – continued

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 246.

		$ million
	2018	2017
Fair value of pension plan assets		
Listed equities – developed markets	**5,191**	9,548
– emerging markets	**950**	2,220
Private equity[a]	**2,792**	2,679
Government issued nominal bonds[b]	**4,263**	2,663
Government issued index-linked bonds[b]	**17,491**	16,177
Corporate bonds[b]	**4,606**	4,682
Property[c]	**2,311**	2,211
Cash	**376**	390
Other	**116**	104
Debt (repurchase agreements) used to fund liability driven investments	**(6,011)**	(5,583)
	32,085	35,091

[a] Private equity is valued as fair value based on the most recent third-party net asset valuation.

[b] Bonds held are denominated in sterling and valued using quoted prices in active markets. Where quoted prices are not available, quoted prices for similar instruments in active markets are used.

[c] Property held is all located in the United Kingdom and are valued based on an analysis of recent market transactions supported by market knowledge derived from third-party valuers.

		$ million
	2018	2017
Analysis of the amount charged to profit or loss		
Current service cost[a]	**295**	357
Past service cost[b]	**15**	12
Operating charge relating to defined benefit plans	**310**	369
Payments to defined contribution plan	**38**	31
Total operating charge	**348**	400
Interest income on plan assets[c]	**(868)**	(845)
Interest on plan liabilities	**773**	830
Other finance (income)	**(95)**	(15)
Analysis of the amount recognized in other comprehensive income		
Actual asset return less interest income on pension plan assets	**(722)**	2,396
Change in financial assumptions underlying the present value of the plan liabilities	**1,768**	(237)
Change in demographic assumptions underlying the present value of plan liabilities	**123**	734
Experience gains and losses arising on the plan liabilities	**520**	91
Remeasurements recognized in other comprehensive income	**1,689**	2,984

[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.

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4. Pensions – continued

	2018	2017
		$ million
Movements in benefit obligation during the year		
Benefit obligation at 1 January	**31,474**	29,871
Exchange adjustments	**(1,587)**	2,882
Operating charge relating to defined benefit plans	**310**	369
Interest cost	**773**	830
Contributions by plan participants[a]	**21**	16
Benefit payments (funded plans)[b]	**(1,780)**	(1,903)
Benefit payments (unfunded plans)[b]	**(4)**	(3)
Remeasurements	**(2,411)**	(588)
Benefit obligation at 31 December	**26,796**	31,474
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	**35,091**	30,180
Exchange adjustments	**(1,883)**	3,048
Interest income on plan assets[c]	**868**	845
Contributions by plan participants[a]	**21**	16
Contributions by employers (funded plans)	**490**	509
Benefit payments (funded plans)[b]	**(1,780)**	(1,903)
Remeasurements[c]	**(722)**	2,396
Fair value of plan assets at 31 December[d e]	**32,085**	35,091
Surplus at 31 December	**5,289**	3,617
Represented by		
Asset recognized	**5,473**	3,838
Liability recognized	**(184)**	(221)
	5,289	3,617
The surplus may be analysed between funded and unfunded plans as follows		
Funded	**5,473**	3,838
Unfunded	**(184)**	(221)
	5,289	3,617
The defined benefit obligation may be analysed between funded and unfunded plans as follows		
Funded	**(26,612)**	(31,253)
Unfunded	**(184)**	(221)
	(26,796)	(31,474)

[a] Most of the contributions made by plan participants were made under salary sacrifice.

[b] The benefit payments amount shown above comprises $1,764 million benefits (2017 $1,888 million) plus $20 million (2017 $18 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 $31,818 million of assets held in the BP Pension Fund (2017 $34,841 million) and $203 million held in the BP Global Pension Trust (2017 $183 million), as well as $51 million representing the company's share of Merchant Navy Officers Pension Fund (2017 $53 million) and $13 million of Merchant Navy Ratings Pension Fund (2017 $14 million).

[e] The fair value of plan assets includes borrowings related to the LDI programme as described on page 244.

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 2018 for the company's plans would have had the effects shown in the table below. The effects shown for the expense in 2019 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 expense in 2019	**(270)**	**239**
Effect on pension obligation at 31 December 2018	**(4,137)**	**5,527**
Inflation rate[b]		
Effect on pension expense in 2019	**176**	**(145)**
Effect on pension obligation at 31 December 2018	**3,939**	**(3,396)**
Salary growth		
Effect on pension expense in 2019	**37**	**(33)**
Effect on pension obligation at 31 December 2018	**449**	**(411)**

[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 2019 pension expense by $34 million and the pension obligation at 31 December 2018 by $965 million.

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4. 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 2028 and the weighted average duration of the defined benefit obligations at 31 December 2018 are as follows:

	$ million
Estimated future benefit payments	
2019	**1,027**
2020	**1,034**
2021	**1,054**
2022	**1,086**
2023	**1,118**
2024-2028	**5,766**
	Years
Weighted average duration	**17.8**

5. Payables

				$ million
		2018		2017
	Current	**Non-current**	Current	Non-current
Amounts payable to subsidiaries[a]	**14,559**	**31,765**	10,070	31,755
Accruals and deferred income	**31**	**—**	60	—
Other payables	**75**	**35**	73	49
	14,665	**31,800**	10,203	31,804

[a] In 2017, an amount of $2,300 million has been reclassified from non-current payables to current payables.

Included in non-current amounts payable to subsidiaries is an interest-bearing payable of $4,236 million (2017 $4,236 million) with BP International Limited, with interest being charged based on a 3-month USD LIBOR rate plus 55 basis points and a maturity date of December 2021. Also included is an interest-bearing payable of $27,100 million (2017 $27,100 million) with BP International Limited, with interest being charged based on a 3-month USD LIBOR rate plus 65 basis points and a maturity date of May 2023. Current amounts payable to subsidiaries also includes an interest-bearing payable of $5,000 million (2017 $2,300 million) with BP Finance plc, with interest being charged based on a 1-year USD LIBOR rate and a maturity date of April 2020, callable upon demand.

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 payables.

		$ million
	2018	2017
Due within		
1 to 2 years	**40**	73
2 to 5 years	**31,520**	4,530
More than 5 years	**240**	27,201
	31,800	31,804

6. Taxation

		$ million
Tax charge included in total comprehensive income	**2018**	2017
Deferred tax		
Origination and reversal of temporary differences in the current year	**570**	1,158
This comprises:		
Taxable temporary differences relating to pensions	**570**	1,158
Deferred tax		
Deferred tax liability		
Pensions	**1,907**	1,337
Net deferred tax liability	**1,907**	1,337
Analysis of movements during the year		
At 1 January	**1,337**	179
Charge (credit) for the year in the income statement	**59**	(11)
Charge (credit) for the year in other comprehensive income	**511**	1,169
At 31 December	**1,907**	1,337

At 31 December 2018, deferred tax assets of $258 million on other temporary differences, $7 million relating to pensions, $67 million relating to income losses and $184 million relating to other deductible temporary differences (2017 $92 million relating to other temporary differences and $8 million relating to pensions) were not recognized as it is not considered probable that suitable taxable profits will be available in the company from which the future reversal of the underlying temporary differences can be deducted. There is no fixed expiry date for the unrecognised temporary differences.

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7. Called-up share capital

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

Issued	2018 Shares thousand	2018 $ million	2017 Shares thousand	2017 $ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9
		21		21
Ordinary shares of 25 cents each				
At 1 January	**21,288,193**	**5,322**	21,049,696	5,263
Issue of new shares for the scrip dividend programme	**195,305**	**49**	289,789	72
Issue of new shares for employee share-based payment plans	**92,168**	**23**	—	—
Repurchase of ordinary share capital	**(50,202)**	**(13)**	(51,292)	(13)
At 31 December	**21,525,464**	**5,381**	21,288,193	5,322
		5,402		5,343

[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.

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.

During 2018 the company repurchased 50 million ordinary shares at a cost of $355 million, including transaction costs of $2 million, as part of the share repurchase programme announced on 31 October 2017. All shares purchased were for cancellation. The repurchased shares represented 0.2% of ordinary share capital.

Treasury shares[a]

	2018 Shares thousand	2018 Nominal value $ million	2017 Shares thousand	2017 Nominal value $ million
At 1 January	**1,482,072**	**370**	1,614,657	403
Purchases for settlement of employee share plans	**757**	**—**	4,423	1
Issue of new shares for employee share-based payment plans	**92,168**	**23**	—	—
Shares re-issued for employee share-based payment plans	**(148,732)**	**(37)**	(137,008)	(34)
At 31 December	**1,426,265**	**356**	1,482,072	370
Of which - shares held in treasury by BP	**1,264,732**	**316**	1,472,343	368
- shares held in ESOP trusts	**161,518**	**40**	9,705	2
- shares held by BP's US plan administrator[b]	**15**	**—**	24	—

[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 6.9% (2017 7.5%) of the called-up ordinary share capital of the company.

During 2018, the movement in shares held in treasury by BP represented less than 1.0% (2017 less than 0.5%) of the ordinary share capital of the company.

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.

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8. Capital and reserves – continued

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) and by BP's US share plan administrator 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 currency 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 (2017 $24,107 million), the distribution of which is limited by statutory or other restrictions.

The financial statements for the year ended 31 December 2018 do not reflect the dividend announced on 5 February 2019 and paid in March 2019; this will be treated as an appropriation of profit in the year ended 31 December 2019.

9. Financial guarantees

The company has issued guarantees under which the maximum aggregate liabilities at 31 December 2018 were $77,965 million (2017 $75,824 million), the majority of which relate to finance debt of subsidiaries. Also included are guarantees of subsidiaries' liabilities under the Consent Decree between the United States, the Gulf states and BP and under the settlement agreement with the Gulf states in relation to the Gulf of Mexico oil spill. The company has also issued uncapped indemnities and guarantees, including a guarantee of subsidiaries' liabilities under the Plaintiffs' Steering Committee agreement relating to the Gulf of Mexico oil spill. Uncapped indemnities and guarantees are also issued in relation to potential losses arising from environmental incidents involving ships leased and operated by a subsidiary.

10. Share-based payments

Effect of share-based payment transactions on the company's result and financial position

		$ million
	2018	2017
Total expense recognized for equity-settled share-based payment transactions	**429**	397
Total (credit) expense recognized for cash-settled share-based payment transactions	**(9)**	9
Total expense recognized for share-based payment transactions	**420**	406
Closing balance of liability for cash-settled share-based payment transactions	**27**	54
Total intrinsic value for vested cash-settled share-based payments	**23**	58

Additional information on the company's share-based payment plans is provided in Note 11 to the consolidated financial statements.

11. Auditor's remuneration

Note 36 to the consolidated financial statements provides details of the remuneration of the company's auditor on a group basis.

12. Directors' remuneration

		$ million
Remuneration of directors	**2018**	2017
Total for all directors		
Emoluments	**8**	9
Amounts awarded under incentive schemes[a]	**16**	9
Total	**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. Further information is provided in the Directors' remuneration report on page 87.

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13. Employee costs and numbers

Employee costs	2018	2017
		$ million
Wages and salaries	**491**	496
Social security costs	**74**	74
Pension costs	**80**	92
	645	662

Average number of employees	2018	2017
Upstream	**269**	262
Downstream	**1,151**	1,125
Other businesses and corporate	**2,344**	2,384
	3,764	3,771

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14. Related undertakings of the group

In accordance with Section 409 of the Companies Act 2006, a full list of related undertakings, the registered office address and the percentage of equity owned as at 31 December 2018 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.

All subsidiary undertakings are controlled by the group and their results are fully consolidated in the group's financial statements.

The percentage of equity owned by the group is 100% unless otherwise noted below.

The stated ownership percentages represent the effective equity owned by the group.

Subsidiaries

200 PS Overseas Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
4321 North 800 West LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
563916 Alberta Ltd. (99.90%)	240- Fourth Avenue SW, Calgary AB T2P 4H4, Canada
ACP (Malaysia), Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Actomat B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Advance Petroleum Holdings Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Advance Petroleum Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
AE Cedar Creek Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Goshen II Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Goshen II Wind Farm LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Power Services LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Wind PartsCo LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Air BP Albania SHA	Aeroporti Nderkombetar i Tiranes, "Nene Tereza", Post Box 2933 in Tirana, Albania
Air BP Brasil Ltda.	Avenida Rouxinol, 55 , Offices 501-514 , Moema Office Tower, São Paulo, 04516- 000, Brazil
Air BP Canada LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Air BP Croatia d.o.o.	Petrinjska ulica 2, Zagreb, Croatia
Air BP Denmark ApS	Arne Jacobsens Allé 7, 5th Floor, 2300, Copenhagen, Denmark
Air BP Finland Oy	Öljytie 4, 01530 Vantaa, Finland
Air BP Iceland	Armula 24, 108, Reykjavik, Iceland
Air BP Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Air BP Norway AS	P.O. Box, 153 Skoyen, Oslo, 0212, Norway
Air BP Sales Romania S.R.L.	59 Aurel Vlaicu Street, Otopeni, Ilfov County, Romania
Air BP Sweden AB	Box 8107, 10420, Stockholm, Sweden
Air Refuel Pty Ltd[b]	398 Tingira Street, Pinkenba QLD 4008, Australia
Allgreen Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
AM/PM International Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
American Oil Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco (Fiddich) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Amoco (U.K.) Exploration Company, LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Bolivia Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Bolivia Services Company Inc.	Craigmuir Chambers, P.O. Box 71, Road Town, Tortola, British Virgin Islands
Amoco Canada International Holdings B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Amoco Capline Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Chemical (Europe) S.A.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Chemicals (FSC) B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Amoco CNG (Trinidad) Limited	5-5A Queen's Park West, Port-of-Spain, Trinidad and Tobago
Amoco Cypress Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Destin Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Endicott Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Environmental Services Company	Bank of America Center, 16th Floor, 1111 East Main Street, Richmond VA 23219, United States
Amoco Exploration Holdings B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Amoco Fabrics and Fibers Ltd.[c]	1423 Cameron Street, Hawkesbury ON, Canada
Amoco Guatemala Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco International Finance Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco International Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Leasing Corporation	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Louisiana Fractionator Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Main Pass Gathering Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Marketing Environmental Services Company	400 East Court Avenue, Des Moines IA 50309, United States
Amoco MB Fractionation Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco MBF Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Netherlands Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Nigeria Exploration Company Limited[d]	7M8 Ligali Ayorinde Street, Victoria Island, Lagos, Nigeria
Amoco Nigeria Oil Company Limited[d]	7M8 Ligali Ayorinde Street, Victoria Island, Lagos, Nigeria
Amoco Nigeria Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Nigeria Petroleum Company Limited	7M8 Ligali Ayorinde Street, Victoria Island, Lagos, Nigeria

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Amoco Norway Oil Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Oil Holding Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Olefins Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Overseas Exploration Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Pipeline Asset Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Pipeline Holding Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Properties Incorporated	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Realty Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Remediation Management Services Corporation	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Research Operating Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Rio Grande Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Somalia Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Sulfur Recovery Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Trinidad Gas B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Amoco Tri-States NGL Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco U.K. Petroleum Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
AmProp Finance Company	251 East Ohio Street, Suite 500, Indianapolis IN 46204, United States
Amprop Illinois I Limited Partnership[e]	801 Adlai Stevenson Drive, Springfield, IL, 62703, United States
Amprop, Inc.	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Anaconda Arizona, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Arabian Production And Marketing Lubricants Company (50.00%)	Riyadh Airport Road, Business Gate, Building C2, 2nd Floor., Saudi Arabia
Aral Aktiengesellschaft	Wittener Straße 45, 44789 Bochum, Germany
Aral Luxembourg S.A.	Bâtiment B, 36route de Longwy, L-8080 Bertrange, Luxembourg
Aral Services Luxembourg Sarl	Autoroute A3/E25, L-3325 Brechem Ouest, Luxembourg
Aral Tankstellen Services Sarl	Bâtiment B, 36route de Longwy, L-8080 Bertrange, Luxembourg
Aral Vertrieb GmbH	Überseeallee 1, 20457, Hamburg, Hamburg, Germany
ARCO British International, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO British Limited, LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Coal Australia Inc.	Level 17, 717 Bourke Street, Docklands VIC, Australia
ARCO El-Djazair Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO El-Djazair LLC	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Environmental Remediation, L.L.C.[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Exploration, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Gaviota Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Ghadames Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO International Investments Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO International Services Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Material Supply Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Mediterraneo Inversiones, S.L	Federico García Lorca, 43, entreplanta, 04004, Almería, Spain
ARCO Midcon LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Oil Company Nigeria Unlimited[a]	7M8 Ligali Ayorinde Street, Victoria Island, Lagos, Nigeria
ARCO Oman Inc.	Providence House, East Hill Street, P.O. Box N-3944, Nassau, Bahamas
ARCO Products Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Resources Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
ARCO Terminal Services Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Trinidad Exploration and Production Company Limited	Providence House, East Hill Street, P.O. Box N-3944, Nassau, Bahamas
ARCO Unimar Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Areas Noriega S.L.	Ronda de Poniente 3, 1ªPlanta, 28760 Tres Cantos, Madrid, Spain
Areas Singulares Reyes S.L.	Calle Velázquez 18, 28001 Madrid, Spain
Aspac Lubricants (Malaysia) Sdn. Bhd. (63.03%)	Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia
Atlantic 2/3 UK Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Atlantic Richfield Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Autino Holdings Limited (88.85%)[f]	83-85 London Street , Reading , Berkshire, RG1 4QA, United Kingdom
Autino Limited (88.85%)	83-85 London Street , Reading , Berkshire, RG1 4QA, United Kingdom
Auwahi Wind Energy Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
B2Mobility GmbH	Wittener Straße 45, 44789 Bochum, Germany
Bahia de Bizkaia Electridad, S.L. (75.00%)	Atraque Punta Lucero, Explanada Punta Ceballos s/n, Ziérbena (Vizcaya), Spain
Baltimore Ennis Land Company, Inc.	1300 East Ninth Street, Cleveland, OH, 44114, United States
BHP Billiton Petroleum (Eagle Ford Gathering) LLC (75.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BHP Billiton Petroleum (KCS Resources), LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BHP Billiton Petroleum (Tx Gathering), LLC[a]	The Corporation Company, 1833 South Morgan Road,, Oklahoma City OK 73128, United States
BHP Billiton Petroleum (TxLa Operating) Company	350 North St. Paul Street, Suite 2900, Dallas, Texas 75201, United States
BHP Billiton Petroleum (WSF Operating), Inc.	5615 Corporate Blvd., Suite 400B, Baton Rouge LA 70808, United States
BHP Billiton Petroleum Properties (GP), LLC[a]	CT Corporation System, 1021 Main Street, Suite 1150, Houston, Texas 77002, United States

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

BHP Billiton Petroleum Properties (LP) LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BHP Billiton Petroleum Properties (N.A.), LP[e]	1999 Bryan St., STE 900, Dallas TX 75201, United States
Black Lake Pipe Line Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP- Castrol (Thailand) Limited (57.57%)[g]	23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa Sathon, Bangkok 10120, Thailand
BP (Abu Dhabi) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (Barbados) Holding SRL	Erin Court, Bishop's Court Hill, St. Michael , Barbados
BP (Barbican) Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (China) Holdings Limited[a]	Room 2101, 21F Youyou International Plaza, 76 Pujian Road, Pudong, Shanghai, PRC
BP (China) Industrial Lubricants Limited[a]	Bin Jiang Road, Petrochemical Industrial Park, Jiangsu Province, China
BP (Gibraltar) Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (Indian Agencies) Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (Malta) Limited (in liquidation)[h]	3rd Floor, Navi Buildings, Pantar Road, Lija, LJA 2021, Malta
BP (Shandong) Petroleum Co., Ltd[a]	Room 1-2201, Sijian Meilin Mansion, No. 48-15 Wuyingshan Middle Road, Tianqiao District, Ji'nan, Shandong, China
BP (Shanghai) Trading Limited[a]	No. 28 Maji Road, Donghua Financial Building, China (Shanghai) Pilot Free Trade, Shanghai, China
BP Absheron Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Advanced Mobility Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Africa Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Akaryakit Ortakligi (70.00%)[e]	Degirmen yolu cad. No:28, Asia OfisPark K:3 İcerenkoy-Atasehir, Istanbul, 34752, Turkey
BP Alaska LNG LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Alternative Energy Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Alternative Energy Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Alternative Energy North America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP America Chembel Holding LLC	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP America Chemicals Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP America Foreign Investments Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP America Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP America Production Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP AMI Leasing, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Amoco Chemical Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Amoco Chemical Holding Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Amoco Chemical Indonesia Limited	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
BP Amoco Chemical Malaysia Holding Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Amoco Chemical Singapore Holding Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
BP Amoco Exploration (Faroes) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Amoco Exploration (In Amenas) Limited	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
BP Angola (Block 18) B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Argentina Exploration Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Argentina Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Aromatics Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Aromatics Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Asia Limited	Unit 807, Tower B, Manulife Financial Centre, 223 Wai Yip Street, Kwun Tong, Kowloon, Hong Kong
BP Asia Pacific (Malaysia) Sdn. Bhd.	Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia
BP Asia Pacific Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Asia Pacific Pte Ltd[h]	7 Straits View #26-01, Marina One East Tower, Singapore, 018936, Singapore
BP Australia Capital Markets Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Employee Share Plan Proprietary Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Group Pty Ltd[d]	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Investments Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Nominees Proprietary Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Shipping Pty Ltd[j]	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Swaps Management Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Aviation A/S	c/o Danish Refuelling Services, Kastrup Lufthavn, 2770 Kastrup, Denmark
BP Benevolent Fund Trustees Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Berau Ltd.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Biocombustíveis S.A. (91.10%)	Avenida das Nações Unidas, 12399, 4fl, Sao Paulo, Brazil
BP Bioenergia Campina Verde Ltda. (91.10%)	Rua Principal, Fazenda Recanto, Caixa Postal 01, Ituiutaba, Minas Gerais, 38.300-898, Brazil
BP Bioenergia Ituiutaba Ltda. (81.26%)	Fazenda Recanto, Zona Rural, CEP 38.300-898, Ituiutaba, Minas Gerais, Brazil
BP Bioenergia Itumbiara S.A. (73.95%)	Estrada Municipal Itumbiara, Chacoeira Dourada, Fazenda Jandaia, Itumbiara, Goiás, 75516-126, Brazil
BP Bioenergia Tropical S.A. (94.04%)	Rodovia GO 410, km 51 à esquerda, Fazenda Canadá, s/n, Zona Rural, Edéia, Goiás, 75940-000, Brazil
BP Biofuels Advanced Technology Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Biofuels Brazil Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Biofuels Louisiana LLC[a]	5615 Corporate Blvd., Suite 400B, Baton Rouge LA 70808, United States
BP Biofuels North America LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Biofuels Trading Comércio, Importação e Exportação Ltda. (81.18%)	Avenida das Nações Unidas, 12399, 4fl, Sao Paulo, Brazil

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

BP Bomberai Ltd.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Brasil Ltda.	Avenida das Américas, no. 3434, Salas 301 a 308, Barra da Tijuca, Rio de Janeiro, RJ, 22640-102, Brazil
BP Brazil Tracking L.L.C.[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Bulwer Island Pty Ltd[k]	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Business Service Centre Asia Sdn Bhd	Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia
BP Business Service Centre KFT[a]	BP Business Service Centre KFT, 32-34 Soroksári út, H-1095 Budapest, Hungary
BP Canada Energy Development Company	Stewart McKelvey, 900, 1959 Upper Water Street, Halifax NS B3J 3N2, Canada
BP Canada Energy Group ULC	Stewart McKelvey, 900, 1959 Upper Water Street, Halifax NS B3J 3N2, Canada
BP Canada Energy Marketing Corp.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Canada International Holdings B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Canada Investments Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Capellen Sarl	Aire de Capellen, L-8309 Capellen, Luxembourg
BP Capital Markets America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Capital Markets p.l.c.	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Car Fleet Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Caribbean Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Castrol KK (64.84%)	East Tower 20F, Gate CIty Ohsaki, 1-11-2 Osaki, Shinagawa-ku, Tokyo, Japan
BP Castrol Lubricants (Malaysia) Sdn. Bhd. (63.03%)	Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia
BP Chembel N.V.	Amocolaan 2 2440 Geel , Belgium
BP Chemicals (Korea) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Chemicals East China Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Chemicals Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Chemicals Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Chemicals Trading Limited (In Liquidation)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP China Exploration and Production Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP China Limited (In Liquidation)[h]	55 Baker Street, London, W1U 7EU, United Kingdom
BP Comercializadora de Energia Ltda.	Avenida das Nações Unidas, 12399, 4fl, Sao Paulo, Brazil
BP Commodities Trading Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Commodity Supply B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Company North America Inc.	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
BP Containment Response Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Containment Response System Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Continental Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Corporate Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Corporation North America Inc.	150 West Market Street, Suite 800, Indianapolis IN 46204, United States
BP D230 Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Danmark A/S	Arne Jacobsens Allé 7, 5th Floor, 2300, Copenhagen, Denmark
BP D-B Pipeline Company LLC[e]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Developments Australia Pty. Ltd.	Level 8, 250 St Georges Terrace, Perth WA 6000, Australia
BP Diagnostic Acoustic Sensing Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Dogal Gaz Ticaret Anonim Sirketi	Degirmen yolu cad. No:28, Asia OfisPark K:3 İcerenkoy-Atasehir, Istanbul, 34752, Turkey
BP East Kalimantan CBM Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Eastern Mediterranean Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Egypt Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Egypt East Delta Marine Corporation	Craigmuir Chambers, P.O. Box 71, Road Town, Tortola, British Virgin Islands
BP Egypt East Tanka B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Egypt Production B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Egypt Ras El Barr B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Egypt West Mediterranean (Block B) B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Energía México, S. de R.L. de C.V.	Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico
BP Energy Asia Pte. Limited	7 Straits View #26-01, Marina One East Tower, Singapore, 018936, Singapore
BP Energy Colombia Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Energy Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Energy do Brasil Ltda.	Avenida das Américas, no. 3434, Salas 301 a 308, Barra da Tijuca, Rio de Janeiro, RJ, 22640-102, Brazil
BP Energy Europe Limited	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
BP Energy Solutions B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Espana, S.A. Unipersonal[k]	Avenida de Barajas 30, Parque Empresarial Omega, Edificio D. 28108 Alcobendas, Madrid, Spain
BP Estaciones y Servicios Energéticos, Sociedad Anónima de Capital Variable[b]	Avenida Santa Fe 505, Piso 10, Distrito Federal, Mexico C.P. 0534, Mexico
BP Europa SE[l]	Überseeallee 1, 20457, Hamburg, Hamburg, Germany
BP Exploracion de Venezuela S.A.	Av. Francisco de Miranda, Edif Cavendes, Los Palos Grandes, Chacao, Caracas Miranda, 1060, Venezuela
BP Exploration & Production Inc.[c]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Exploration (Absheron) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Alaska) Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Exploration (Algeria) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Alpha) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Angola) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Azerbaijan) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

BP Exploration (Canada) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Caspian Sea) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Delta) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (El Djazair) Limited	Providence House, East Hill Street, P.O. Box N-3910, Nassau, Bahamas
BP Exploration (Epsilon) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Finance) Limited (In Liquidation)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Greenland) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Madagascar) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Morocco) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Namibia) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Nigeria Finance) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Nigeria) Limited	Landmark Towers- 5B, Water Corporation Road, Victoria Island, Lagos, Nigeria
BP Exploration (Shafag-Asiman) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Shah Deniz) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (South Atlantic) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (STP) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Vietnam) Limited (In Liquidation)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Xazar) Pte. Ltd.	7 Straits View #26-01, Marina One East Tower, Singapore, 018936, Singapore
BP Exploration Angola (Kwanza Benguela) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Australia Pty Ltd	Level 8, 250 St Georges Terrace, Perth WA 6000, Australia
BP Exploration Beta Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration China Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Company (Middle East) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Company Limited[m]	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
BP Exploration Indonesia Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Libya Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Mexico Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Mexico, S.A. De C.V.[b]	Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico
BP Exploration North Africa Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Operating Company Limited[k]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Orinoco Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Personnel Company Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Express Shopping Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Finance Australia Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Finance p.l.c.	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Foundation Incorporated[a]	251 East Ohio Street, Suite 500, Indianapolis IN 46204, United States
BP France	Immeuble Le Cervier, 12 Avenue des Béguines, Cergy Saint Christophe, 95866, Cergy Pontoise, France
BP Fuels & Lubricants AS	P.O.Box 153 Skøyen, 0212 Oslo, Norway
BP Fuels Deutschland GmbH	Wittener Straße 45, 44789 Bochum, Germany
BP Gas Europe, S.A.U.	Avenida de Barajas 30, Parque Empresarial Omega, Edificio D. 28108 Alcobendas, Madrid, Spain
BP Gas Marketing Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Gas Supply (Angola) LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Ghana Limited	Number 12, Aviation Road, Una Home 3rd Floor, Airport City , Accra, Greater Accra, PMB CT 42, Ghana
BP Global Investments Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Global Investments Salalah & Co LLC	PO Box 2309, Salalah, 211, Oman
BP Global West Africa Limited	Heritage Place, 7th Floor, Left Wing, 21 Lugard Avenue, Ikoyi, Lagos, Nigeria
BP GOM Logistics LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Greece Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Guangdong Limited (90.00%)[a]	Rm 2710Guangfa Bank Plaza, No. 83 Nonglin Xia Road, Yuexiu District, Guangzhou, China
BP High Density Polyethylene- France	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
BP Holdings (Thailand) Limited (81.01%)[n]	39/77-78 Moo 2 Rama II Road, Tambon Bangkrachao, Amphur Muang, Samutsakorn 74000, Thailand
BP Holdings B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Holdings Canada Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Holdings International B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Holdings North America Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Hong Kong Limited	Unit 807, Tower B, Manulife Financial Centre, 223 Wai Yip Street, Kwun Tong, Kowloon, Hong Kong
BP India Limited	Technopolis Knowledge Park, Mahakali Caves Road, Andheri (East), Mumbai 400 093, India
BP India Services Private Limited	Technopolis Knowledge Park, Mahakali Caves Road, Andheri (East), Mumbai 400 093, India
BP Indonesia Investment Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP International Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP International Services Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
BP Investment Management Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Investments Asia Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Iran Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Iraq N.V.	Amocolaan 2 2440 Geel , Belgium
BP Italia SpA	Via Verona 12, Cornaredo, 20010, Milan, Italy
BP Japan K.K.	Roppongi Hills Mori Tower, 10-1 Roppongi 6-chome, Minato-ku, Tokyo106-6115, Japan

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

BP Kapuas II Limited (in liquidation)	55 Baker Street, London, W1U 7EU, United Kingdom
BP Korea Limited	2nd Floor, Woojin Bldg., 76-4, Jamwon-dong, Seocho-gu, Seoul 137-909, Republic of Korea
BP Kuwait Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Latin America LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Latin America Upstream Services Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP LNG Shipping Limited	Clarendon House, 2 Church Street, P.O. Box HM 1022, Hamilton, HM DX, Bermuda
BP Lubricants KK (64.84%)	East Tower 20F, Gate CIty Ohsaki, 1-11-2 Osaki, Shinagawa-ku, Tokyo, Japan
BP Lubricants USA Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Luxembourg S.A.	Aire de Capellen, L-8309 Capellen, Luxembourg
BP Malaysia Holdings Sdn. Bhd. (70.00%)	Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia
BP Management International B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Management Netherlands B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Marine Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Mariner Holding Company LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Maritime Services (Isle of Man) Limited	Samuel Harris House, 5-11 St Georges Street, Douglas, Isle of Man, IM1 1AJ, Isle of Man
BP Maritime Services (Singapore) Pte. Limited	7 Straits View #26-01, Marina One East Tower, Singapore, 018936, Singapore
BP Marketing Egypt LLC	Plot 28, North 90 Road, Housing & Construction Bank Building, New Cairo, Cairo, 11835, Egypt
BP Mauritania Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Mauritius Limited (In Liquidation)	5th Floor, Ebene Esplanade, 24 Cybercity, Ebene, Mauritius
BP Middle East Enterprises Corporation	Craigmuir Chambers, P.O. Box 71, Road Town, Tortola, British Virgin Islands
BP Middle East Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Middle East LLC	P.O.Box 1699, Dubai, 1699, United Arab Emirates
BP Midstream Partners GP LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Midstream Partners Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Midstream Partners LP (54.37%)[o]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Mocambique Limitada	Society and Geography Avenue, Plot No. 269 , Third floor, Maputo, Mozambique
BP Mocambique Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Muturi Holdings B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Nederland Holdings BV	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Netherlands Upstream B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP New Ventures Middle East Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP New Zealand Holdings Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
BP New Zealand Share Scheme Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
BP Nutrition Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Offshore Gathering Systems Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Offshore Pipelines Company LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Offshore Response Company LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Oil (Thailand) Limited (90.32%)[p]	39/77-78 Moo 2 Rama II Road, Tambon Bangkrachao, Amphur Muang, Samutsakorn 74000, Thailand
BP Oil Australia Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Oil Espana, S.A. Unipersonal	Polígono Industrial "El Serrallo", s/n 12100 Grao de Castellón, Castellón de la Plana, Spain
BP Oil Hellenic S.A.	26 Kifissias Ave. and 2 Paradissou st., 15125 Maroussi, Athens, Greece
BP Oil International Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Kent Refinery Limited (in liquidation)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Llandarcy Refinery Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Logistics UK Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil New Zealand Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
BP Oil Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Oil Shipping Company, USA	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Oil UK Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Venezuela Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Vietnam Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Yemen Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Olex Fanal Mineralol GmbH	Überseeallee 1, 20457, Hamburg, Hamburg, Germany
BP Pacific Investments Ltd	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
BP Pakistan (Badin) Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Pakistan Exploration and Production, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Pension Trustees Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pensions (Overseas) Limited[i]	Albert House, South Esplanade, St. Peter Port, GY1 1AW, Guernsey
BP Pensions Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Petrochemicals India Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Petroleo y Gas, S.A.	Av. Francisco de Miranda, Edif Cavendes, Los Palos Grandes, Chacao, Caracas Miranda, 1060, Venezuela
BP Petrolleri Anonim Sirketi	Degirmen yolu cad. No:28, Asia OfisPark K:3 İcerenkoy-Atasehir, Istanbul, 34752, Turkey
BP Pipelines (Alaska) Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Pipelines (BTC) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pipelines (North America) Inc.	45 Memorial Circle, Augusta ME 04330, United States
BP Pipelines (SCP) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pipelines (TANAP) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pipelines TAP Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

BP Polska Services Sp. z o.o.	Ul. Jasnogórska 1, 31-358 Kraków, Malopolskie, Poland
BP Portugal-Comercio de Combustiveis e Lubrificantes SA	Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal
BP Poseidon Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Products North America Inc.	351 West Camden Street, Baltimore MD 21201, United States
BP Properties Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Raffinaderij Rotterdam B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Refinery (Kwinana) Proprietary Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Regional Australasia Holdings Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP River Rouge Pipeline Company LLC[e]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Russian Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Russian Ventures Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP SC Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Scale Up Factory Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Senegal Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Services International Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Servicios de Combustibles S.A. de C.V.	Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico
BP Servicios territoriales, S.A. de C.V.	Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico
BP Shafag-Asiman Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Shipping Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Singapore Pte. Limited	7 Straits View #26-01, Marina One East Tower, Singapore, 018936, Singapore
BP Solar Energy North America LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Solar Espana, S.A. Unipersonal[b]	Avenida de Barajas 30, Parque Empresarial Omega, Edificio D. 28108 Alcobendas, Madrid, Spain
BP Solar International Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Solar Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP South America Holdings Ltd	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP South East Asia Limited (In Liquidation)[h]	55 Baker Street, London, W1U 7EU, United Kingdom
BP Southern Africa Proprietary Limited (75.00%)	BP House, 10 Junction Avenue, Parktown, Johannesburg, 2193, South Africa
BP Southern Cone Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Subsea Well Response (Brazil) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Subsea Well Response Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Taiwan Marketing Limited	7FNo. 71Sec. 3Min Sheng East Road, Taipei, Taiwan
BP Tanjung IV Limited (In Liquidation)	55 Baker Street, London, W1U 7EU, United Kingdom
BP Technology Ventures Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Technology Ventures Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Trading Limited (In Liquidation)	55 Baker Street, London, W1U 7EU, United Kingdom
BP Train 2/3 Holding SRL	Erin Court, Bishop's Court Hill, St. Michael , Barbados
BP Transportation (Alaska) Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Trinidad and Tobago LLC (70.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Trinidad Processing Limited	5-5A Queen's Park West, Port-of-Spain, Trinidad and Tobago
BP Turkey Refining Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Two Pipeline Company LLC[e]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Venezuela Investments B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP West Aru I Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP West Aru II Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP West Coast Products LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP West Papua I Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP West Papua III Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Wind Energy North America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Wiriagar Ltd.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP World-Wide Technical Services Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Zhuhai Chemical Company Limited (91.90%)[a]	Da Ping Harbour, Lin Gang Industrial Zone, Zhuhai City, Guangdong Province, China
BP+Amoco International Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BPA Investment Holding Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP-AIOC Exploration (TISA) LLC (65.88%)[a]	153 Neftchilar Avenue, Baku, AZ1010, Azerbaijan
BPNE International B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BPRY Caribbean Ventures LLC (70.00%)[a]	RL&F Service Corp, 920 North King Street, 2nd Floor, Wilmington DE 19801, United States
BPX Energy Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Brian Jasper Nominees Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Britannic Energy Trading Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Britannic Investments Iraq Limited (90.00%)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Britannic Marketing Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Britannic Strategies Limited	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
Britannic Trading Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
British Pipeline Agency Limited (50.00%)[g q]	5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS, United Kingdom
Britoil Limited	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
BTC Pipeline Holding Company Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Burmah Castrol Australia Pty Ltd[r]	Level 17, 717 Bourke Street, Docklands VIC, Australia

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14. Related undertakings of the group – continued

Burmah Castrol Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Burmah Castrol PLC[h]	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
Burmah Castrol South Africa (Pty) Limited[s]	BP House, 10 Junction Avenue, Parktown, Johannesburg, 2193, South Africa
Burmah Chile SpA	José Musalen Saffie, Huerfanos N° 770 Of. 301, Santiago, Chile
BXL Plastics Limited[t]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Cadman DBP Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Cape Vincent Wind Power, LLC[a]	111 Eighth Avenue, New York, New York, 10011, United States
Casitas Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Castrol (China) Limited	Unit 807, Tower B, Manulife Financial Centre, 223 Wai Yip Street, Kwun Tong, Kowloon, Hong Kong
Castrol (Ireland) Limited	2 Grand Canal Square, Dublin 2, Dublin, Ireland
Castrol (Shanghai) Management Co., Ltd[a]	Floor 20, Shanghai Youyou International Plaza, No.76 Pujian Road, Pudong, Shanghai, China
Castrol (Shenzhen) Company Limited[a]	No.1120 Mawan Road, Nanshan District, China
Castrol (Tianjin) Lubricants Co., Ltd[a]	Tianjin Economic Development Area, China
Castrol (U.K.) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Castrol Australia Pty. Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
CASTROL Austria GmbH[a]	Straße 6, Objekt 17, Industriezentrum NÖ-Süd, 2355 Wr. Neudorf, Austria
Castrol B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Castrol BP Petco Limited Liability Company (65.00%)[a]	22-36 Nguyen Hue Street, 57-69F Dong Khoi Street, District 1, Ho Chi Minh City, Vietnam
Castrol Brasil Ltda.	Avenida das Américas, no. 3434, Salas 301 a 308, Barra da Tijuca, Rio de Janeiro, RJ, 22640-102, Brazil
Castrol Caribbean & Central America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Castrol Colombia Limitada	KR 7 NO. 74 09, Bogota D.C., Colombia
Castrol Del Peru S.A. (99.49%)	Av. Camino Real, 111 Torre B Oficina, 603 San Isidro, Lima, Peru
Castrol Digital Holdings Limited	Technology Centre, Whitchurch Hill, Pangbourne, Reading, RG8 7QR, United Kingdom
Castrol Egypt Lubricants S.A.E. (51.00%)	Plot 28, North 90 Road, Housing & Construction Bank Building, New Cairo, Cairo, 11835, Egypt
Castrol Hungária Trading Co. LLC "u.d." (Castrol Hungária Kereskedelmi Kft. "v.a.")[a]	32-34 Soroksári út, Budapest, 1095, Hungary
Castrol India Limited (51.00%)	Technopolis Knowledge Park, Mahakali Caves Road, Andheri (East), Mumbai 400 093, India
Castrol Industrie und Service GmbH	Erkelenzer Straße 20, 41179 Mönchengladbach, Germany
Castrol KK (64.84%)	East Tower 20F, Gate CIty Ohsaki, 1-11-2 Osaki, Shinagawa-ku, Tokyo, Japan
Castrol Limited	Technology Centre, Whitchurch Hill, Pangbourne, Reading, RG8 7QR, United Kingdom
Castrol Lubricants RO S.R.L	5th Floor, 92-96 Izvor St, 5th District, Bucharest, Romania
Castrol Mexico, S.A. de C.V.[b]	Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico
Castrol Namibia (Pty) Limited	BP House, 10 Junction Avenue, Parktown, Johannesburg, 2193, South Africa
Castrol Offshore Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Castrol Pakistan (Private) Limited	D-67/1, Block # 4, Scheme # 5, , Clifton, Karachi, Pakistan, Karachi, Pakistan
Castrol Philippines, Inc.	32/F LKG Tower, Ayala Avenue, Makati City, 6801, Philippines
Castrol Servicos Ltda.	Avenida Tamboré, 448, Barueri, Sao Paulo, Brazil
Castrol Slovensko, s.r.o. (v likvidácii) (in liquidation)[a]	Rožnavská 24, 821 04 Bratislava 2, Slovakia
Castrol Ukraine LLC[a]	2a Konstiantynivskay Street, Kyiv, 04071, Ukraine
Castrol Zimbabwe (Private) Limited	Barking Road, Willowvale, Harare, Zimbabwe
Centrel Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Charge Your Car Limited[b]	500 Capability Green, Luton, LU1 3LS, United Kingdom
Chargemaster (Europe) GmbH	Bischof-von-Henle-Straße 2a, Regensburg, 93051, Germany
Chargemaster Limited	500 Capability Green, Luton, LU1 3LS, United Kingdom
Charging Solutions Limited	500 Capability Green, Luton, LU1 3LS, United Kingdom
CH-Twenty, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Clarisse Holdings Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Coastwise Trading Company, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Consolidada de Energia y Lubricantes, (CENERLUB) C.A.	Av. Eugenio Mendoza, San Felipe Edificio Centro Letonia, La Castellana, Caracas, 1060, Venezuela
Conti Cross Keys Inn, Inc.	Easton and Swamp Roads, Buckinham Township, Bucks County, Pennsylvania, United States
Corner Card, S.L.	Ronda de Poniente 3, 1ªPlanta, 28760 Tres Cantos, Madrid, Spain
Coro Trading NZ Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
Cuyama Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Dermody Developments Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Dermody Holdings Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Dermody Investments Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Dermody Petroleum Pty. Ltd.	Level 17, 717 Bourke Street, Docklands VIC, Australia
DHC Solvent Chemie GmbH	Timmerhellstsr. 28, 45478, Mülheim/Ruhr, Germany
Dome Beaufort Petroleum Limited	240- 4th Avenue SW, Calgary AB T2P 4H4, Canada
Dome Beaufort Petroleum Limited (March 1980) Limited Partnership[e]	240- Fourth Avenue SW, Calgary AB T2P 4H4, Canada
Dome Beaufort Petroleum Limited 1979 Partnership No. 1[e]	240- Fourth Avenue SW, Calgary AB T2P 4H4, Canada
Dome Wallis (1980) Limited Partnership (92.50%)[e]	240- Fourth Avenue SW, Calgary AB T2P 4H4, Canada
Dradnats, Inc.	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
ECM Markets SA (Pty) Ltd (75.00%)	BP House, 10 Junction Avenue, Parktown, Johannesburg, 2193, South Africa
Elektromotive Limited	500 Capability Green, Luton, LU1 3LS, United Kingdom

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14. Related undertakings of the group – continued

Elite Customer Solutions Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Elm Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Energy Global Investments (USA) Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Enstar LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Estacion De Servicio Molinar S.L.	Ronda de Poniente 3, 1ªPlanta, 28760 Tres Cantos, Madrid, Spain
Europa Oil NZ Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
Exomet, Inc.	1300 East Ninth Street, Cleveland, OH, 44114, United States
Expandite Contract Services Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Exploration (Luderitz Basin) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Exploration Service Company Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Flat Ridge 2 Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Flat Ridge Wind Energy, LLC[a]	112 SW 7th Street, Suite 3C, Topeka, Kansas, 66603, United States
Foseco Holding International B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Foseco Holding, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Foseco, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fosroc Expandite Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Fowler Ridge Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge I Land Investments LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge II Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge III Wind Farm LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
FreeBees B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Fuel & Retail Aviation Sweden AB	Box 8107, 10420, Stockholm, Sweden
Fuelplane- Sociedade Abastecedora De Aeronaves, Unipessoal, Lda	Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal
FWK (2017) Limited[u]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
FWK Holdings (2017) LTD[u]	Chertsey Road , Sunbury on Thames , TW16 7BP, United Kingdom
Gardena Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Gasolin GmbH	Wittener Straße 45, 44789 Bochum, Germany
GB Electrical and Building Services Limited	500 Capability Green, Luton, LU1 3LS, United Kingdom
Gelsenkirchen Raffinerie Netz GmbH	Alexander-von-Humboldt-Straße 1, Gelsenkirchen, 45896, Germany
GOAM 1 C.I S. A .S	Calle 80 No.11-42, Bogota, 110111, Colombia
Grampian Aviation Fuelling Services Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Guangdong Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Highlands Ethanol, LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Hosteleria Noriega S.L.	Ronda de Poniente 3, 1ªPlanta, 28760 Tres Cantos, Madrid, Spain
Hydrogen Energy International Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
IGI Resources, Inc.	12550 W. Explorer Dr., Suite 100, Boise, Idaho, 83713, United States
Insight Analytics Solutions Holdings Limited (74.50%)	Romax Technology Centre , University of Nottingham Innovation Park, Triumph Road, Nottingham, NG7 2TU, United Kingdom
Insight Analytics Solutions Limited (74.50%)	Romax Technology Centre , University of Nottingham Innovation Park, Triumph Road, Nottingham, NG7 2TU, United Kingdom
Insight Analytics Solutions USA, Inc (74.50%)	2108 55th Street, Suite 105, Boulder CO 80301, United States
International Bunker Supplies Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
International Card Centre Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Iraq Petroleum Company Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Jupiter Insurance Limited	The Albany, South Esplanade, St Peter Port, GY1 4NF, Guernsey
Ken-Chas Reserve Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Kenilworth Oil Company Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Kingbook Inversiones Socimi, S.A.	Calle Velázquez 18, 28001 Madrid, Spain
Latin Energy Argentina S.A.	Av. Cordoba 315 Piso 8, Buenos Aires, 1054, Argentina
Lebanese Aviation Technical Services S.A.L.	P O Box- 11-5814c/o Coral Oil Building, 583Avenue de Gaulle, Raoucheh, Beirut, Lebanon
Limited Liability Company BP Toplivnaya Kompania[a]	Novinskiy blvd.8, 17th floor, office 11, 121099, Moscow, Russian Federation
Limited liability company Setra Lubricants[a]	2 Paveletskaya sq, Building1, 115054 Moscow, Russian Federation
Lubricants UK Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Mardi Gras Transportation System Company LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Markoil, S.A. Unipersonal	Avenida de Barajas 30, Parque Empresarial Omega, Edificio D. 28108 Alcobendas, Madrid, Spain
Masana Petroleum Solutions (Pty) Ltd (37.88%)	BP House, 10 Junction Avenue, Parktown, Johannesburg, 2193, South Africa
Mayaro Initiative for Private Enterprise Development (70.00%)[a]	5-5A Queen's Park West, Port-of-Spain, Trinidad and Tobago
Mehoopany Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Mes Tecnologia en Servicios y Energia, S.A. De C.V.[b]	Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico
Minza Pty. Ltd.	Level 17, 717 Bourke Street, Docklands VIC, Australia
Mountain City Remediation, LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
No. 1 Riverside Quay Proprietary Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
Nordic Lubricants A/S	Arne Jacobsens Allé 7, 5th Floor, 2300, Copenhagen, Denmark
Nordic Lubricants AB	Hemvärnsgatan , 171 54, Solna, Sweden
Nordic Lubricants Oy, (in liquidation)	Teknobulevardi 3-5, 01530 Vantaa, Finland
North America Funding Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

OMD87, Inc.	111 Eighth Avenue, New York, New York, 10011, United States
Omega Oil Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
OnSight Analytics Solutions India Private Ltd. (74.50%)	#11, Platinum Tower, Ground Floor, Old Trunk Road, Pallavaram Chennai, India
OOO BP STL[a]	Novinskiy blvd.8, 17th floor, office 11, 121099, Moscow, Russian Federation
Orion Delaware Mountain Wind Farm LP[a]	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Orion Energy Holdings, LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Orion Energy L.L.C.[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Orion Post Land Investments, LLC[a]	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Pacroy (Thailand) Co., Ltd. (39.00%)	23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa Sathon, Bangkok 10120, Thailand
Peaks America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Pearl River Delta Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Petrocorner Retail S.L.U.	Ronda de Poniente 3, 1ªPlanta, 28760 Tres Cantos, Madrid, Spain
Petrohawk Energy Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Phoenix Petroleum Services, Limited Liability Company	Baghdad International Airport, Al-Burhan Commercial Complex , First floor, Baghdad, Iraq
Produits Métallurgie Doittau	Immeuble Le Cervier, 12 Avenue des Béguines, Cergy Saint Christophe, 95866, Cergy Pontoise, France
Prospect International, C.A. (In liquidation)	Av. Eugenio Mendoza, San Felipe Edificio Centro Letonia, La Castellana, Caracas, 1060, Venezuela
PT BP Petrochemicals Indonesia	20th Floor Summitmas II Jl., Jend. Sudirman Kav. 61- 62, Jakarta, Selatan, Indonesia
PT Castrol Indonesia (68.30%)	Perkantoran Hijau Arkadia, Tower B, Jl. Let. Jenderal TB. Simatupang Kav. 88, Jakarta12520, Indonesia
PT Castrol Manufacturing Indonesia	JL. Raya Merak KM 117, DS Gerem, Gerem Grogol, Cilegon, Banten, Indonesia
PT Jasatama Petroindo[b]	Perkantoran Hijau Arkadia, Tower B, Jl. Let. Jenderal TB. Simatupang Kav. 88, Jakarta12520, Indonesia
Remediation Management Services Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Richfield Oil Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Rolling Thunder I Power Partners, LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Romax Insight Korea Limited (74.50%)	504 Cheong dan ro-213-3, Young pyung dong 2170-1 Jeju Science Park Smart Building, Jeju City, Jeju-do, Korea, Republic of
Ropemaker Deansgate Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Ropemaker Properties Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Ruhr Oel GmbH (ROG)	Johannastraße 2-8, 45899 Gelsenkirchen-Horst, Germany
Rusdene GSS Limited[u]	4 High Street, Alton, Hampshire, GU34 1BU, United Kingdom
Saturn Insurance Inc.	400 Cornerstone Drive, Suite 240, Williston VT 05495, United States
Setra Lubricants Kazakhstan LLP (in liquidation)[e]	98 Panfilov Street, office 809, Almaty, 05000, Kazakhstan
Sherbino I Holdings LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Sherbino Mesa I Land Investments LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Shine Top International Investment Limited	Unit 807, Tower B, Manulife Financial Centre, 223 Wai Yip Street, Kwun Tong, Kowloon, Hong Kong
Sociedade de Promocao Imobiliaria Quinta do Loureiro, SA	Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal
Société de Gestion de Dépots d'Hydrocarbures- GDH[a]	Immeuble Le Cervier, 12 Avenue des Béguines, Cergy Saint Christophe, 95866, Cergy Pontoise, France
SOFAST Limited (62.77%)[v]	23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa Sathon, Bangkok 10120, Thailand
South Texas Shale LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Southeast Texas Biofuels LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Southern Ridge Pipeline Holding Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Southern Ridge Pipeline LP LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Sp/f Decision3 (GreenSteam) Company (61.68%)[w]	Krosslíð 11, FO-100 Tórshavn , Faroe Islands
SRHP (99.99%)[a]	Immeuble Le Cervier, 12 Avenue des Béguines, Cergy Saint Christophe, 95866, Cergy Pontoise, France
Standard Oil Company, Inc.	251 East Ohio Street, Suite 500, Indianapolis IN 46204, United States
Taradadis Pty. Ltd.	Level 17, 717 Bourke Street, Docklands VIC, Australia
Telcom General Corporation (99.96%)[c]	818 West Seventh Street, 2nd Floor, Los Angeles, CA, 90017, United States
Terre de Grace Partnership (75.00%)[e]	1100, 635- 8th Avenue SW, Calgary AB T2P 3M3, Canada
The Anaconda Company	814 Thayer Avenue, Bismarck, ND, 58501-4018, United States
The BP Share Plans Trustees Limited[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
The Burmah Oil Company (Pakistan Trading) Limited	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
The Standard Oil Company	4400 Easton Commons Way , Suite 125, Columbus OH 43219, United States
TISA Education Complex LLC (65.88%)[a]	153 Neftchilar Avenue, Baku, AZ1010, Azerbaijan
TJKK	Roppongi Hills Mori Tower, 10-1 Roppongi 6-chome, Minato-ku, Tokyo106-6115, Japan
Toledo Refinery Holding Company LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Union Texas International Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Vastar Pipeline, LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Viceroy Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Warrenville Development Limited Partnership[a]	33 North LaSalle Street, Chicago, Illinois 60602, United States
Water Way Trading and Petroleum Services LLC (90.00%)	Hay Al Wihda, Q904, Alley 68, H32, Korodha, Baghdad, Iraq
Welchem, Inc.	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
West Kimberley Fuels Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Westlake Houston Development, LLC[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Whiting Clean Energy, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Windpark Energy Nederland B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Winwell Resources, L.L.C.[a]	5615 Corporate Blvd., Suite 400B, Baton Rouge LA 70808, United States
Wiriagar Overseas Ltd	Jayla Place, Wickhams Cay 1, PO Box 3190, Road Town, Tortola, VG1110, British Virgin Islands

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Related undertakings other than subsidiaries

A Flygbranslehantering AB (AFAB) (25.00%)	Box 135, 190 46 Arlanda, Sweden
Aashman Power Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
ABG Autobahn-Betriebe GmbH (32.58%)[a]	Brucknerstraße 4, 1041 Wien, Austria
Abu Dhabi Marine Areas Limited (33.33%)[g]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Advanced Biocatalytics Corporation (24.20%)[x]	18010 Skypark Circle , #130 , Irvine CA 92614, United States
AEP I HoldCo LLC (24.30%)	Harvard Business Services, Inc., 16192 Coastal Hwy, Lewes, Delaware, 19958, USA
AGES International GmbH & Co. KG, Langenfeld (24.70%)[e]	Berghausener Straße 96, 40764 Langenfeld, Germany
AGES Maut System GmbH & Co. KG, Langenfeld (24.70%)[e]	Berghausener Straße 96, 40764 Langenfeld, Germany
Air BP Copec S.A. (51.00%)	Patricio Raby Benavente, Moneda N° 920 Of 205, Santiago, Chile
Air BP Italia Spa (50.00%)	Via Lazio 20/C, 00187 Roma, Italy
Air BP PBF del Peru S.A.C. (50.00%)	Avenida Ricardo Rivera Navarrete n.501 / room 1602, Lima, Peru
Air BP Petrobahia Ltda. (50.00%)	Av. Anita Garibaldi, n.252, 2o floor, Ala Sul, Federação, Salvador, Bahia, 40210-750, Brazil
Aircraft Fuel Supply B.V. (28.57%)	Oude Vijfhuizerweg 6, 1118LV Luchthaven, Schiphol, Netherlands
Aircraft Refuelling Company GmbH (33.33%)[a]	Trabrennstraße 6-8 3, A-1020, Wien, Austria
Airport Fuel Services Pty. Limited (20.00%)	Level 12, 680 George Street, Sydney NSW 2000, Australia
Aker BP ASA (30.00%)	Oksenoyveien 10, , 1366 Lysaker, Norway
Alaska Tanker Company, LLC (25.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Alyeska Pipeline Service Company (48.44%)	9360 Glacier Highway, Suite 202, Juneau AK 99801, United States
Ambarli Depolama Hizmetleri Limited Sirketi (51.00%)	Yakuplu Mahallesi Genc, Osman Caddesi, No.7 Beylikdüzü, Istanbul, Turkey
Ammenn GmbH (75.00%)	Luisenstraße 5 a, 26382 Wilhelmshaven, Germany
ATAS Anadolu Tasfiyehanesi Anonim Sirketi (68.00%)[y]	Degirmen yolu cad. No:28, Asia OfisPark K:3 İcerenkoy-Atasehir, Istanbul, 34752, Turkey
Atlantic 1 Holdings LLC (34.00%)[a]	RL&F Service Corp, 920 North King Street, 2nd Floor, Wilmington DE 19801, United States
Atlantic 2/3 Holdings LLC (42.50%)[a]	RL&F Service Corp, 920 North King Street, 2nd Floor, Wilmington DE 19801, United States
Atlantic 4 Holdings LLC (37.78%)[a]	RL&F Service Corp, 920 North King Street, 2nd Floor, Wilmington DE 19801, United States
Atlantic LNG 2/3 Company of Trinidad and Tobago Unlimited (42.50%)	Princes Court, Cor. Pembroke & Keate Street, Port-of-Spain, Trinidad and Tobago
Atlantic LNG 4 Company of Trinidad and Tobago Unlimited (37.78%)	Princes Court, Cor. Pembroke & Keate Street, Port-of-Spain, Trinidad and Tobago
Atlantic LNG Company of Trinidad and Tobago (34.00%)	Princes Court, Cor. Pembroke & Keate Street, Port-of-Spain, Trinidad and Tobago
Atlas Methanol Company Unlimited (36.90%)	Maracaibo Drive, Point Lisas Industrial Estate, Point Lisas, Trinidad and Tobago
Australasian Lubricants Manufacturing Company Pty Ltd (50.00%)[g]	Building 1, 747 Lytton Road, Murarrie QLD 4172, Australia
Australian Terminal Operations Management Pty Ltd (50.00%)	Level 3, Unit 3, 22 Albert Road, South Melbourne VIC 3205, Australia
Auwahi Holdings, LLC (50.00%)[a]	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Auwahi Wind Energy LLC (50.00%)[a]	National Registered Agents, Inc., 160 Greentree Dr., Dover, Delaware, 19904, United States
Aviation Fuel Services Limited (25.00%)	Calshot Way Central Area, Heathrow Airport, Hounslow, Middlesex, TW6 1PY, United Kingdom
Axion Comercializacion de Combustibles y Lubricantes S.A. (50.00%)	Luis A de Herrera 1248, Torre II, Piso 22 (Edificio World Trade Center), Montevideo, Uruguay
Axion Energy Argentina S.A. (50.00%)	Carlos María Della Paolera 265, Piso 22, Ciudad Autónoma de Buenos Aires, Argentina
Axion Energy Holding S.L. (50.00%)[a]	Campus Empresarial Arbea- Edificio No 1, Carretera Fuencarral a Alcobendas, Alcobendas, Madrid, Spain
Axion Energy Paraguay S.R.L. (50.00%)[a]	Av. España 1369 esquina San Rafael, Asunción, Paraguay
Axuy Energy Holdings S.R.L. (50.00%)[a]	Avenida Luis Alberto de Herrera 1248, Oficina 1901, Montevideo, Uruguay
Axuy Energy Investments S.R.L. (50.00%)[a]	Avenida Luis Alberto de Herrera 1248, Oficina 1901, Montevideo, Uruguay
Azerbaijan Gas Supply Company Limited (23.06%)[g]	P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
Azerbaijan International Operating Company (30.37%)[z]	190 Elgin Avenue, George Town, Grand Cayman , KY1-9005, Cayman Islands
Baplor S.A. (50.00%)	Colonia 810, Oficina 403, Montevideo, Uruguay
Barranca Sur Minera S.A. (50.00%)	Calle 14, No 781, Piso 2, Oficina 3, Ciudad de La Plata, Provincia de Buenos Aires, Argentina
Beer GmbH (50.00%)	Saganer Straße 31, 90475 Nürnberg, Germany
Beer GmbH & Co. Mineralol-Vertriebs-KG (50.00%)[e]	Saganer Straße 31, 90475 Nürnberg, Germany
BGFH Betankungs-Gesellschaft Frankfurt-Hahn GbR (50.00%)[e]	Sportallee 6, 22335 Hamburg, Germany
Billund Refuelling I/S (50.00%)	GA Centervej 1, DK-7190, Billund, Denmark
Blendcor (Pty) Limited (37.50%)[α]	135 Honshu Road, Islandview, Durban, 4052, South Africa
Blue Marble Holdings Limited (23.58%)[β]	Desklodge- 5th Floor, 1 Temple Way, Bristol, BS2 0BY, United Kingdom
Bodmin Solar Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
BP AOC Pumpstation Maatschap (50.00%)[e]	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
BP Dhofar LLC (49.00%)	P.O.Box 20302/211, 20302, Oman
BP Esso AOC Maatschap (22.80%)[e]	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
BP Esso Pipeline Maatschap (50.00%)[e]	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
BP Guangzhou Development Oil Product Co., Ltd (40.00%)[a]	No.13 Longxue Road, Longxue Island, Nansha District, Guangzhou, Guangdong, 511450, China
BP Petro China Jiangmen Fuels Co., Ltd. (49.00%)[a]	Room A, building B , 5th floor, no. 22 Gangang Road, Jiangmen, China
BP PetroChina Petroleum Co., Ltd (49.00%)[a]	Room A17th Floor, No.22 Gangkou Road, Jiangmen, Guangdong Province, China

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BP PETRONAS Acetyls Sdn. Bhd. (70.00%)	Symphony House, Pusat Dagangan Dana 1, Jalan PJU 1A/46, 47301 Petaling Jaya, Selangor, Malaysia
BP Sinopec (ZheJiang) Petroleum Co., Ltd (40.00%)[a]	12 Hua Zhe Plaza, 1 Hua Zhe Square, Hang Zhou City, Zhe Jiang Province, China
BP Sinopec Marine Fuels Pte. Ltd. (50.00%)	112 Robinson Road, #05-01, Robinson 112, 068902, Singapore
BP West Africa Supply Limited (50.00%)	Number 1, Rehoboth Place, Dade Street, North Labone Estates, Accra, Accra Metropolitan, Greater Accra, P. O. BOX CT3278, Ghana
BP YPC Acetyls Company (Nanjing) Limited (50.00%)[a]	9# Huo Ju Road, Liu He District, Nanjing, Jiangsu Province, China
BP-Husky Refining LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP-Japan Oil Development Company Limited (50.00%)[g]	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
Braendstoflageret Kobenhavns Lufthavn I/S (20.83%)[e]	Københavns, Lufthavn, 2770 Kastrup, Denmark
BTC International Investment Co. (30.10%)[r]	P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
Burnthouse Solar Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Butamax™ Advanced Biofuels LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Caesar Oil Pipeline Company, LLC (56.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Cairns Airport Refuelling Service Pty Ltd (33.33%)	680 George Street, Sydney NSW 2000, Australia
Cantera K-3 Limited Partnership (39.00%)[e]	6400 Shafer Ct., Suite 400, Rosemont IL 60018-4927, United States
Canton Renewables, LLC (50.00%)[a]	30600 Telegraph Road, Suite 2345, Bingham Farms MI 48025, United States
Castrol Cuba S.A. (50.00%)	Calle 6 No 319, esq 5ta. Ave., Miramar, Playa, La Habana, Cuba
Castrol DongFeng Lubricant Co., Ltd (50.00%)[a]	Room 1404-1405, Donghe Centre Tower B, 3 Sanjiao Hu Road, Wuhan, Hubei Province, China
Cedar Creek II Holdings LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Cedar Creek II, LLC (50.00%)[a]	1560 Broadway, Suite 2090, Denver, Colorado, 80202, United States
Cefari RNG OKC, LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Cekisan Depolama Hizmetleri Limited Sirketi (35.70%)	Yakuplu Ambarli Mevkii, 9 Ada2-3-6-7 Parsel, Büyükçekmece, Istanbul, Turkey
Central African Petroleum Refineries (Pvt) Ltd (20.75%)	Block 1 Tendeseka Office Park, Samora Machel Av/Renfrew Road, Harare, Zimbabwe
CERF Shelby, LLC (50.00%)[a]	800 S. Gay Street, Suite 2021, Knoxville TN 37929, United States
Chicap Pipe Line Company (56.17%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
China American Petrochemical Company, Ltd. (CAPCO) (61.36%)	6th Floor, No. 413 Section 2 Ruei Kuang Road, Neihhu, Taipei, 11493, Taiwan
China Aviation Oil (Singapore) Corporation Ltd (20.03%)	8 Temasek Boulevard #31-02, Suntec City Tower 3, Singapore 038988, Singapore
Chittering Solar Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Clean Eagle RNG, LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Cleopatra Gas Gathering Company, LLC (53.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Coastal Oil Logistics Limited (25.00%)	10th Floor, The Bayleys Building, Cnr Brandon St and Lambton Quay, Wellington, 6011, New Zealand
Compania de Inversiones El Condor Limitada (99.00%)	Av. Andrés Bello 2711, Piso 24, Las Condes, Santiago, Chile
Concessionaria Stalvedro SA (50.00%)	San Gottardo Sud, 6780, Airolo, Switzerland
CSG Convenience Service GmbH (24.80%)	Wittener Straße 45, 44789 Bochum, Germany
Danish Refuelling Service I/S (33.33%)[e]	Kastrup Lufthavn, 2770 Kastrup, Denmark
Danish Tankage Services I/S (50.00%)[e]	Kastrup Lufthavn, 2770 Kastrup, Denmark
Dinarel S.A. (20.00%)	La Cumparsita 1373, piso 4°, Montevideo, Uruguay
Donoma Power Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
DOPARK GmbH (25.00%)	Westfalendamm 166, 44141 Dortmund, Germany
Dusseldorf Fuelling Services GbR (33.00%)[e]	Sportallee 6, 22335 Hamburg, Germany
Dusseldorf Tank Services GbR (33.00%)[e]	Sportallee 6, 22335 Hamburg, Germany
East Tanka Petroleum Company "ETAPCO" (50.00%)	4 Palestine Road, 4th District, New Maadi, Cairo, Egypt
Ekma Oil Company "EKMA" (50.00%)	4 Palestine Road, 4th District, New Maadi, Cairo, Egypt
El Temsah Petroleum Company "PETROTEMSAH" (25.00%)	5 El Mokhayam El Daiem St, 6th Sector, Nasr City, Egypt
EMDAD Aviation Fuel Storage FZCO (33.33%)	P.O.Box 261781, Dubai, United Arab Emirates
Emoil Storage Company FZCO (20.00%)	Plot No. B003R04, Box No. 9400, Dubai, United Arab Emirates, Dubai, United Arab Emirates
EMSEP S.A. de C.V. (50.00%)	Av. Paseo de la Reforma 505 piso 32, Colonia Cuauhtémoc, Delegación Cuauhtémoc (06500), CDMX, Mexico
Endymion Oil Pipeline Company, LLC (65.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Energy Emerging Investments, LLC (50.00%)[a]	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Entrepot petrolier de Chambery (32.00%)	562 Avenue du Parc de l'Ile, 92000, Nanterre, France
Entrepôt Pétrolier de Puget sur Argens- EPPA (58.25%)	Immeuble Le Cervier, 12 Avenue des Béguines, Cergy Saint Christophe, 95866, Cergy Pontoise, France
Erdol-Lagergesellschaft m.b.H. (23.00%)[a]	Radlpaßstraße 6, 8502 Lannach, Austria
Esma Petroleum Company "ESMA" (50.00%)	4 Palestine Road, 4th District, New Maadi, Cairo, Egypt
Estonian Aviation Fuelling Services	Lennujaama tee 2, Tallinn EE0011, Estonia
Etzel-Kavernenbetriebsgesellschaft mbH & Co. KG (33.00%)[e]	Bertrand-Russell-Straße 3, 22761 Hamburg, Germany
Etzel-Kavernenbetriebs-Verwaltungsgesellschaft mbH (33.33%)	Bertrand-Russell-Straße 3, 22761 Hamburg, Germany
Ffos Las Solar Developments Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
FFS Frankfurt Fuelling Services (GmbH & Co.) OHG (33.00%)[e]	Sportallee 6, 22335 Hamburg, Germany

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14. Related undertakings of the group – continued

Field Services Enterprise S.A. (50.00%)	Av. Leandro N. Alem 1180, piso 11, Buenos Aires, Argentina
Finite Carbon Corporation (50.00%)	435 Devon Park Drive, Suite 700, Wayne, Pennsylvania, 19087
Finite Resources, Inc. (50.00%)	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Fip Verwaltungs GmbH (50.00%)	Rheinstraße 36, 49090 Osnabrück, Germany
Flat Ridge 2 Wind Energy LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Flat Ridge 2 Wind Holdings LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Flughafen Hannover Pipeline Verwaltungsgesellschaft mbH (50.00%)	Überseeallee 1, 20457, Hamburg, Germany
Flughafen Hannover Pipelinegesellschaft mbH & Co. KG (50.00%)[e]	Überseeallee 1, 20457, Hamburg, Hamburg, Germany
Flytanking AS (50.00%)	Postboks 36, Stjordal, NO-7501, Norway
Foreseer Ltd (25.00%)	121A Thoday Street, Cambridge , Cambridgeshire, CB1 3AT , United Kingdom
Formosa BP Chemicals Corporation (50.00%)	No. 1-1Formosa Industrial Comples, Mailiao, Yunlin Hsien, Taiwan
Fotech Group Limited (22.40%)[x]	5th Floor, Condor House, 10 St Paul's Churchyard, London, EC4M 8AL , United Kingdom
Fowler I Holdings LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler II Holdings LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge II Wind Farm LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge Wind Farm LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Free Power for Schools 13 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 14 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 15 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 17 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 19 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 4 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 5 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 6 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 7 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Freetricity Central June Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Freetricity Commercial June Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Fuelling Aviation Service- FAS (50.00%)[a]	3 Rue des Vignes, Aéroport Charles de Gaulle, 93290, Tremblay en France, France
Fundación para la Eficiencia Energética de la Comunidad Valenciana (33.33%)[a]	Calle Lituania nº 10, Castellón de la Plana, Spain
Gardermeon Fuelling Services AS (33.33%)	Postboks 133, Gardermoen, NO-2061, Norway
Gemalsur S.A. (50.00%)	Colonia 810, Oficina 403, Montevideo, Uruguay
Georgian Pipeline Company (30.37%)[z]	190 Elgin Avenue, George Town, Grand Cayman , KY1-9005, Cayman Islands
Gezamenlijke Tankdienst Schiphol B.V. (50.00%)	Anchoragelaan 6, 1118 LD Schiphol, Netherlands
GISSCO S.A. (50.00%)	2,Vouliagmenis Ave & Papaflessa, 16777 Elliniko, Athens, Attika, Greece
Gnowee Power Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Goshen Phase II LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Gothenburgh Fuelling Company AB (GFC) (33.33%)	Box 2154, 438 14, LANDVETTER, Sweden
Gravcap, Inc. (25.00%)	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Groupement Pétrolier de Saint Pierre des Corps-GPSPC (20.00%)[a]	150 Avenue Yves Farge, 37700, Saint Pierre des Corps, France
Guangdong Dapeng LNG Company Limited (30.00%)[a]	10-11/FTime Finance Center, No.4001 Shennan Dadao, Shenzhen, Guangdong Province, China
Gulf Of Suez Petroleum Company "GUPCO" (50.00%)	4 Palestine Road, 4th District, New Maadi, Cairo, Egypt
GVÖ Gebinde-Verwertungsgesellschaft der Mineralölwirtschaft mbH (21.00%)	Steindamm 55, 20099 Hamburg, Germany
H7 Energy Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Hamburg Tank Service (HTS) GbR (33.00%)[e]	Sportallee 6, 22335 Hamburg, Germany
Hebei Dongming Yinglun Petroleum Co., Ltd. (49.00%)[a]	South Side, Floor 10, Insurance Industrial Park, No. 672, Chengjiao Street, Qiaoxi, Shijiazhuang, Hebei Province, China
Heinrich Fip GmbH & Co. KG (50.00%)[e]	Rheinstraße 36, 49090 Osnabrück, Germany
Heliex Power Limited (32.40%)[x]	Kelvin Building , Bramah Avenue , East Kilbride, Glasgow , Scotland, G75 0RD, United Kingdom
Henan Dongming Yinglun Petroleum Co., Ltd. (49.00%)[a]	Room 124, Longhu Enterprise Service Center, Floor 1, Building No. 10, Courtyard No.1, Long Xing Jia Yuan, No. 66, Longhu Outer Ring Road, Zhengdong New District, Zhenzhou City
HFS Hamburg Fuelling Services GbR (25.00%)[e]	Sportallee 6, 22335 Hamburg, Germany
Hiergeist Heizolhandel GmbH & Co. KG (50.00%)[e]	Grubenweg 4, 83666 Waakirchen-Marienstein, Germany
Hiergeist Verwaltung GmbH (50.00%)	Grubenweg 4, 83666 Waakirchen-Marienstein, Germany
Hokchi Energy S.A. de C.V. (50.00%)	Torre A, Calzada Legaria 549, Colonia 10 de Abril, Ciudad de Mexico, C. P. 11250, Mexico
Hokchi Iberica S.L. (50.00%)	Campus Empresarial Arbea- Edificio No 1, Carretera Fuencarral a Alcobendas, Alcobendas, Madrid, Spain
Howbery Solar Park Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
In Salah Gas Ltd (25.50%)[α]	22 Grenville Street, St Helier, JE4 8PX, Jersey
In Salah Gas Services Ltd (25.50%)[α]	22 Grenville Street, St Helier, JE4 8PX, Jersey
India Gas Solutions Private Limited (50.00%)	2nd North Avenue, Bandra- Kurla Complex, Bandra (East), Mumbai 400 051, Maharashtra, India
Jamaica Aircraft Refuelling Services Limited (51.00%)[g]	PCJ Building36 Trafalgar Road, Kingston 10, Jamaica
Johnson Corner Solar I, LLC (43.20%)[a]	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware, 19904, United States
Kala Power Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Kingston Research Limited (50.00%)	C/O Banks Cooper Associates, 21 Marina Court, Hull, HU1 1TJ, United Kingdom
Klaus Köhn GmbH (50.00%)	An der Braker Bahn 22, 26122 Oldenburg, Germany
KM Phoenix Holdings LLC (25.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Köhn & Plambeck GmbH & Co. KG (50.00%)[e]	An der Braker Bahn 22, 26122 Oldenburg, Germany
Kosmos Energy Investments Senegal Limited (49.99%)[g]	6th Floor, 65 Gresham Street, London, England and Wales, EC2V 7NQ, United Kingdom
Kurt Ammenn GmbH & Co. KG (50.00%)[e]	Luisenstraße 5 a, 26382 Wilhelmshaven, Germany
LCA Aviation Fuelling Systems Limited (35.00%)	90 Archiepiskopou str, Dromolaxia – Meneou, 7020 Larnaca , Cyprus
LFS Langenhagen Fuelling Services GbR (50.00%)[e]	Sportallee 6, 22335 Hamburg, Germany
Lightning Hybrids, LLC (31.60%)[c]	160 Greentree Drive, Suite 101, Dover, County of Kent DE 19904, United States
Lightsource Asset Holdings Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Asset Management Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Australia SPV 1 Pty Limited (43.20%)	CBW' Level 19, 181 William Street, Melbourne, VIC 3000, Australia
Lightsource BP Renewable Energy Investments Limited (43.20%)[δ]	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Commercial Rooftops (Buyback) Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Commercial Rooftops Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Construction Management Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Development Services Australia Pty Ltd (43.20%)	CBW' Level 19, 181 William Street, Melbourne, VIC 3000, Australia
Lightsource Development Services Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Egypt Holdings Limited (43.20%)	7th Floor, Jie Tai Plaza, 218- 222 Zhong Shan Liu Road, Guangzhou, China
Lightsource Finance 55 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Grace 1 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Grace 2 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Grace 3 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Holdings 1 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Holdings 2 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource India Holdings (Mauritius) Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource India Holdings Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource India Investments (UK) Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource India Limited (22.03%)[g]	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource India Maharashtra 1 Holdings Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource India Maharashtra 1 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Kingfisher Holdings Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Kingpin 1 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Kingpin 2 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Kingpin 3 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Labs Holdings Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Labs Limited (41.04%)	Trinity House, Charleston Road, Ranelagh, Dublin 6, D06C8X4, Ireland
Lightsource Largescale Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Midscale Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Nala Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Operations 1 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Operations 2 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Operations 3 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Operations Services Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Pumbaa Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Radiate 1 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Radiate 2 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Raindrop Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Development Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Renewable Energy (Australia) Pty Ltd (43.20%)	CBW' Level 19, 181 William Street, Melbourne, VIC 3000, Australia
Lightsource Renewable Energy (India) Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource Renewable Energy Australia Holdings Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy Development LLC (43.20%)[a]	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware, 19904, United States
Lightsource Renewable Energy Holdings Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

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Lightsource Renewable Energy India Assets Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy India Holdings Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy India Opco Private Limited (43.20%)	No.44/38, 1st Floor, Veerabhadran Street, Valluvarkottam, Nungambakkam, Chennai, 600034, India
Lightsource Renewable Energy India Projects Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy Ireland Limited (43.20%)	Trinity House, Charleston Road, Ranelagh, Dublin 6, D06C8X4, Ireland
Lightsource Renewable Energy Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Renewable Energy Nederland Holdings B.V. (43.20%)	Prins Bernhardplein 200, 1097JB, Amsterdam, Netherlands
Lightsource Renewable Energy Netherlands Holdings Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy North America LLC (43.20%)[a]	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware, 19904, United States
Lightsource Renewable Energy North America Management LLC (43.20%)[a]	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware, 19904, United States
Lightsource Renewable Energy North America Operations LLC (43.20%)[a]	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware, 19904, United States
Lightsource Renewable Services Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Residential NI Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource Residential Rooftops (Buyback) Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Residential Rooftops (PPA) Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Residential Rooftops Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Simba Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Singapore Renewables Holdings Private Limited (43.20%)	8 Marina Boulevard, #05-02 Marina Bay Financial Centre, Singapore
Lightsource Singapore Renewables Private Limited (43.20%)	8 Marina Boulevard, #05-02 Marina Bay Financial Centre, Singapore
Lightsource SPV 10 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 100 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 101 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 104 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 105 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 106 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 108 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 109 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 112 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 114 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 115 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 116 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 118 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 123 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 126 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 127 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 128 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 130 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 133 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 135 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 137 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 138 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 140 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 142 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 143 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 145 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 147 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 149 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 151 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 152 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 154 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 155 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 156 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 160 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 162 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 166 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom

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14. Related undertakings of the group – continued

Lightsource SPV 167 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 169 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 170 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 171 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 174 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 175 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 176 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 179 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 18 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 180 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 182 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 183 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 184 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 185 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 187 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 189 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 19 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 191 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 192 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 196 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 199 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 20 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 200 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 201 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 202 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 203 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 204 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 205 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 206 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 212 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 213 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 214 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 215 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 216 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 217 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 218 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 219 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 220 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 221 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 222 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 223 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 224 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 225 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 226 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 227 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 228 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 229 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 230 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 232 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 233 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 234 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 235 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 236 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 237 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 238 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 239 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 240 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 241 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 242 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 243 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 244 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 245 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 246 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 247 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 248 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 249 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 25 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 250 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

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14. Related undertakings of the group – continued

Lightsource SPV 251 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 252 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 253 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 254 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 255 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 256 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 257 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 258 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 259 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 26 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 260 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 261 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 262 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 263 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 264 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 265 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 266 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 267 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 268 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 269 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 270 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 271 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 272 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 273 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 274 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 275 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 276 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 277 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 278 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 279 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 280 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 281 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 282 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 283 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 284 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 285 (NI) Limited (43.20%)	Scottish Provident Building, 7 Donegall Square West, Belfast, BT1 6JH, United Kingdom
Lightsource SPV 286 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 29 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 32 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 35 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 39 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 40 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 41 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 42 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 44 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 47 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 49 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 5 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 50 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 54 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 56 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 60 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 69 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 73 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 74 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 75 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 76 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 78 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 79 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 8 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 88 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 91 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 92 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 98 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Timon Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Trading Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Trojan 1 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Trojan 2 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Lightsource Viking 1 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Viking 2 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Limited Liability Company TYNGD (20.00%)[a]	Pervomayskaya street, 32A, 678144, Lensk, Sakha (Yakutiya) Republic, Russian Federation
LL Property Services 2 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
LL Property Services Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
LLC "Kharampurneftegaz" (49.00%)[a]	629830, Gubkinskiy town, Yamalo-Nenets Autonomous Okrug, Russian Federation
Lora Solar Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lotos- Air BP Polska Spólka z ograniczoną odpowiedzialnością (50.00%)	Grunwaldzka 472B, 80-309, Gdansk, Poland
LOTTE BP Chemical Co., Ltd (50.94%)	2-2 Sangnam-ri, Chungryang-myun, Ulju-gun, Ulsan 689-863, Republic of Korea
LREHL Renewables India SPV 1 Private Limited (32.79%)	815-816 International Trade Tower, Nehru Place, New Delhi, New Delhi, 110019, India
Maasvlakte Europoort Pipeline Maatschap (50.00%)[e]	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
Maatschap Europoort Terminal (50.00%)[e]	Moezelweg 101, 3198LS Europoort, Rotterdam, Netherlands
Mach Monument Aviation Fuelling Co. Ltd. (70.00%)	Naz City, Building J, Suite 10 Erbil, Iraq
Malmo Fuelling Services AB (33.33%)	Box 22, SE 230 32 Malmö-Sturup, Sweden
Manchester Airport Storage and Hydrant Company Limited (25.00%)	Bircham Dyson Bell, 50 Broadway, London, SW1H 0BL , United Kingdom
Manor Farm (Solar Power) Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Manpetrol S.A. (50.00%)	Francisco Behr 20, Barrio Pueyrredon, Comodoro Rivadavia, Provincia del Chubut, Argentina
Maputo International Airport Fuelling Services (MIAFS) Limitada (50.00%)[a]	Praca Dos Trabalhadores, Nr 09, Distrito Urbano 1, Maputo, Mozambique
Mars Oil Pipeline Company LLC (28.50%)[e]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Masana Employee Share Trust No. 1 (37.88%)[a]	Block B, 2nd Floor, BP House, 10 Junction Avenue, Parktown, 2193, South Africa
Mavrix, LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
McFall Fuel Limited (49.00%)	700 Bond Street, Te Awamutu, New Zealand
Mediteranean Gas Co. "MEDGAS" (25.00%)	5 El Mokhayam El Daiem St, 6th Sector, Nasr City, Egypt
Mehoopany Wind Energy LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Mehoopany Wind Holdings LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Meri Power Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Middle East Lubricants Company LLC (40.00%)	6th Flr City Tower, 2- Sheikh Zayed Road, PO Box 1699, Dubai, United Arab Emirates
Milne Point Pipeline, LLC (50.00%)[a]	900 E. Benson Boulevard, Anchorage, Alaska, 99508, United States
Mobene Beteiligungs GmbH & Co. KG (50.00%)[a]	Spaldingstraße 64, 20097 Hamburg, Germany
Mobene GmbH & Co. KG (50.00%)[e]	Spaldingstraße 64, 20097 Hamburg, Germany
Mobene Verwaltungs-GmbH (50.00%)	Spaldingstraße 64, 20097 Hamburg, Germany
MTS Francis Court Solar Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
MTS Trefinnick Solar Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
N.V. Rotterdam-Rijn-Pijpleiding Maatschappij (RRP) (44.40%)	Butaanweg 215, NL-3196 KC Vondelingenplaat, Rotterdam, 3045, Havennummer , Netherlands
Natural Gas Vehicles Company "NGVC" (40.00%)	85 El Nasr Road, Cairo, Cairo, Egypt
New Zealand Oil Services Limited (50.00%)	Level 3, 139 The Terrace, Wellington, 6011, New Zealand
Newshelf 1310 (RF) Proprietary Limited (37.88%)	Block B, 2nd Floor, BP House, 10 Junction Avenue, Parktown, 2193, South Africa
Nextpower Trevemper Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
NFX Combustíveis Marítimos Ltda. (50.00%)	Avenida Atlântica, no. 1.130, 2nd floor (part), Copacabana, Rio de Janeiro, RJ, 22021-000, Brazil
Nima Power Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Nord-West Oelleitung GmbH (59.33%)	Zum Ölhafen 207, 26384 Wilhelmshaven, Germany
North Ghara Petroleum Company (NOGHCO) (30.00%)	4 Palestine Road, 4th District, New Maadi, Cairo, Egypt
North October Petroleum Company "NOPCO" (50.00%)	4 Palestine Road, 4th District, New Maadi, Cairo, Egypt
Ocwen Energy Pty Ltd (49.50%)	GTH Accounting Group Pty Ltd '2', 1A Kitchener Street, Toowoomba QLD 4350, Australia
Oleoductos Canarios, S.A. (20.00%)	C/ Explanada Tomas Quevedo S/N, 35008 Puerto De La Luz, Las Palmas De G.C, Spain
Olympic Pipe Line Company LLC (70.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Oslo Lufthaven Tankanlegg AS (33.33%)	Postboks 134, Gardermoen, NO-2061, Norway
PAE E & P Bolivia Limited (50.00%)	Trinity Place Annex, Corner of Frederick & Shirley Streets, P.O. Box N-4805, Nassau, Bahamas
PAE Oil & Gas Bolivia Ltda. (50.00%)	Cuarto anillo, Avda. Ovidio Barbery N° 4200,Equipetrol Norte, Santa Cruz de la Sierra, Bolivia
Palk Power Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Pan American Energy Chile Limitada (50.00%)	Nueva de Lyon N° 145, piso 12, oficina 1203, Edificio Costa, Santiago de Chile, Chile
Pan American Energy do Brasil Ltda. (50.00%)[a]	Rua Manoel da Nóbrega n°1280, 10° andar, Sao Paulo, Sao Paulo, 04001-902, Brazil
Pan American Energy Group, S.L. (50.00%)[α]	Campus Empresarial Arbea- Edificio No 1, Carretera Fuencarral a Alcobendas, Alcobendas, Madrid, Spain
Pan American Energy Holdings S.A. (50.00%)	Colonia 810, Oficina 403, Montevideo, Uruguay
Pan American Energy Iberica S.L. (50.00%)	Campus Empresarial Arbea- Edificio No 1, Carretera Fuencarral a Alcobendas, Alcobendas, Madrid, Spain
Pan American Energy Investments Ltd. (50.00%)	Palm Grove House, P.O. Box 438, Road Town, Tortola, British Virgin Islands
Pan American Energy Uruguay S.A. (50.00%)	Colonia 810, Oficina 403, Montevideo, Uruguay
Pan American Energy US LLC (51.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Pan American Energy, S.L. (50.00%)[a]	Campus Empresarial Arbea- Edificio No 1, Carretera Fuencarral a Alcobendas, Alcobendas, Madrid, Spain

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14. Related undertakings of the group – continued

Pan American Fueguina S.A. (50.00%)	O´Higgins N° 194, Rio Grande, Argentina
Pan American Sur S.A. (50.00%)	O´Higgins N° 194, Rio Grande, Argentina
Peninsular Aviation Services Company Limited (25.00%)[h]	P O Box 6369, Jeddah 21442, Saudi Arabia
Pentland Aviation Fuelling Services Limited (50.00%)[b]	6th Floor (c/o Q8 Aviation), Dukes Court, Duke Street, Woking, GU21 5BH, United Kingdom
Petrostock SA (50.00%)	route de Pré-Bois 2, 1214, Vernier, Switzerland
Pharaonic Petroleum Company "PhPC" (25.00%)	70/72 Road 200, Maadi, Cairo, Egypt
Pont Andrew Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Prince William Sound Oil Spill Response Corporation (25.00%)	9360 Glacier Highway, Suite 202, Juneau AK 99801, United States
Proteus Oil Pipeline Company, LLC (65.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
PT Petro Storindo Energi (30.00%)	Bakrie Tower 17th Floor, Rasuna Epicentrum Complex Jl. H.R Rasuna Said, Jakarta, 12940, Indonesia
PT. Aneka Petroindo Raya (49.90%)	AKR Tower 25th floor, Jalan Panjang No.5, Kebon Jeruk, Jakarta, 11530, Indonesia
PT. Dirgantara Petroindo Raya (49.90%)	Wisma AKR, 25th floor, Jalan Panjang No.5, Kebon Jeruk, , Jakarta Barat, 11530, Indonesia
PTE Pipeline LLC (32.00%)[a]	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Raffinerie de Strasbourg (in liquidation) (33.33%)	24 Cours Michelet, 92800, Puteaux, France
Rahamat Petroleum Company (PETRORAHAMAT) (50.00%)	70/72 Road 200, Maadi, Cairo, Egypt
RAPI SA (62.51%)	26 Kifissias Ave. and 2 Paradissou st., 15125 Maroussi, Athens, Greece
Raststaette Glarnerland AG, Niederurnen (20.00%)	Nideracher 1, 8867, Niederurnen, Switzerland
RD Petroleum Limited (49.00%)	Albert Alloo & Sons, 67 Princes Street, Dunedin, New Zealand
Resolution Partners LLP (68.00%)[e]	1675 Broadway, Denver CO 80202, United States
Rhein-Main-Rohrleitungstransportgesellschaft mbH (35.00%)	Godorfer Hauptstraße 186, 50997 Köln, Germany
Rio Grande Pipeline Company (30.00%)[e]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
RMF Holdings Limited (49.00%)	KPMG, 247 Cameron Road, Tauranga, 3110, New Zealand
Romanian Fuelling Services S.R.L. (50.00%)	59 Aurel Vlaicu Street, Otopeni, Ilfov County, Romania
Rosneft Oil Company (19.75%)	26/1 Sofiyskaya Embankment, 115035, Moscow, Russian Federation
Routex B.V. (25.00%)	Strawinskylaan 1725, 1077XX Amsterdam, Netherlands
Rudeis Oil Company "RUDOCO" (50.00%)	4 Palestine Road, 4th District, New Maadi, Cairo, Egypt
S&JD Robertson North Air Limited (49.00%)	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
SABA- Sociedade Abastecedora de Aeronaves, Lda (25.00%)	Grupo Operacional de Combustiveis do Aeroporto de Lisboa, Edificio 19, 1.° Sala Saba, Lisboa, Portugal
SAFCO SA (33.33%)	International airport "El. Venizelos", Athens, Greece
Salzburg Fuelling GmbH (33.00%)[a]	Innsbrucker Bundesstraße 95, 5020 Salzburg, Austria
Saraco SA (20.00%)	route de Pré-Bois 17, 1216, Cointrin, Switzerland
SeaPort Midstream Partners, LLC (49.00%)[a]	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware, 19904, United States
Servicios Logísticos de Combustibles de Aviación, S.L (50.00%)	Vía de los Poblados1, Madrid, Spain
Shakti Power Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Shandong Dongming Yinglun Petroleum Co., Ltd. (49.00%)[a]	Room 01, 08, 09, 10, Floor 11, Block B, , No. 8, Luoyuan Avenue, Lixia District, Jinan City, China
Sharjah Aviation Services Co. LLC (49.00%)[α]	P O Box- 97, Sharjah, United Arab Emirates
Sharjah Pipeline Company LLC (49.00%)	Sharjah 42244, Sharjah, UAE, Sharjah, United Arab Emirates
Shell and BP South African Petroleum Refineries (Pty) Ltd (37.50%)[g]	1 Refinery Road, Prospecton, 4110, South Africa
Shell Mex and B.P. Limited (40.00%)[α]	Shell Centre, London, SE1 7NA, United Kingdom
Shenzhen Cheng Yuan Aviation Oil Company Limited (25.00%)[a]	Fu Yong Town, Bao An county, ShenZhen Airport, Guangdong Province, China
Shenzhen Dapeng LNG Marketing Company Limited (30.00%)[a]	Room 316 Excellence Mansion, No.98 Fuhua 1Rd, Futian District, Shenzhen, China
Sherbino I Wind Farm LLC (50.00%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
SKA Energy Holdings Limited (50.00%)	LOB 16, Suite #309, Jebel Ali Free Zone, Dubai, PO BOX 262794, United Arab Emirates
SM Realisations Limited (In Liquidation) (40.00%)	Shell International Petroleum, Co Ltd, Shell Centre, 8 York Road, London, SE1 7NA , United Kingdom
Société d'Avitaillement et de Stockage de Carburants Aviation "SASCA" (40.00%)[a]	1 Place Gustave Eiffel, 94150, Rungis, France
Société de Gestion de Produits Pétroliers- SOGEPP (37.00%)	27 Route du Bassin Numéro 6, 92230, Gennevilliers, France
Solar Photovoltaic (SPV2) Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Solar Photovoltaic (SPV3) Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
South Caucasus Pipeline Company Limited (28.83%)[α]	P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
South Caucasus Pipeline Holding Company Limited (28.83%)	P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
South Caucasus Pipeline Option Gas Company Limited (28.83%)	P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
South China Bluesky Aviation Oil Company Limited (24.50%)[a]	Baiyun Internation Airport, Guangzhou, China
Stansted Intoplane Company Limited (20.00%)	Causeway House, 1 Dane Street, Bishop's Stortford, Hertfordshire, CM23 3BT, United Kingdom

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14. Related undertakings of the group – continued

STDG Strassentransport Dispositions Gesellschaft mbH (50.00%)	Holstenhofweg 47, 22043 Hamburg, Germany
Stockholm Fuelling Services Aktiebolag (25.00%)	Box 7, 190 45 Arlanda, Sweden
Stonewall Resources Ltd. (50.00%)	Palm Grove House, P.O. Box 438, Road Town, Tortola, British Virgin Islands
Sula Power Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Sun and Soil Renewable 12 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Sunrise Oil Sands Partnership (50.00%)[e]	c/o Husky Oil Operations Limited, 707- 8th Avenue SW, Calgary AB T2P 1H5, Canada
Tankanlage AG Mellingen (33.33%)	Birmenstorferstrasse 2, 5507, Mellingen, Switzerland
TAR- Tankanlage Ruemlang AG (27.32%)	Zwüscheteich, 8153, Rümlang, Switzerland
TAU Tanklager Auhafen AG (50.00%)	Auhafenstrasse 10a, 4132, Muttenz, Switzerland
TCE Participações S.A. (50.00%)	Avenida Paulista, 287, 1st floor, room 10, São Paulo, São Paulo, 01311000, Brazil
Team Terminal B.V. (22.80%)	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
Tecklenburg GmbH (50.00%)	Wesermünder Straße 1, 27729 Hambergen, Germany
Tecklenburg GmbH & Co. Energiebedarf KG (50.00%)[e]	Wesermünder Straße 1, 27729 Hambergen, Germany
Terminales Canarios, S.L. (50.00%)	Carretera de San Andréss/n, La Jurada-María Jiménez, Santa Cruz de Tenerife, Spain
Texaco Esso AOC Maatschap (TEAM) (22.80%)[e]	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
TFSS Turbo Fuel Services Sachsen GbR (20.00%)[e]	Sportallee 6, 22335 Hamburg, Germany
TGC Solar 106 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
TGC Solar 91 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
TGFH Tanklager-Gesellschaft Frankfurt-Hahn GbR (50.00%)[e]	Sportallee 6, 22335 Hamburg, Germany
TGH Tankdienst-Gesellschaft Hamburg GbR (33.33%)[e]	Sportallee 6, 22335 Hamburg, Germany
TGHL Tanklager-Gesellschaft Hannover-Langenhagen GbR (50.00%)e	Sportallee 6, 22335 Hamburg, Germany
TGK Tanklagergesellschaft Koln-Bonn (25.00%)[e]	Sportallee 6, 22335 Hamburg, Germany
Thames Electricity Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
The Baku-Tbilisi-Ceyhan Pipeline Company (30.10%)[γ]	P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
The Consolidated Petroleum Company Limited (50.00%)[α]	Shell Centre, London, SE1 7NA, United Kingdom
The Consolidated Petroleum Supply Company Limited (50.00%)[ε]	Shell Centre, London, SE1 7NA, United Kingdom
The Sullom Voe Association Limited (33.33%)[α]	Town Hall, Lerwick, Shetland, ZE1 0HB, United Kingdom
TLK Holding Company LLC (37.04%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
TLK Intermediate Holding Company LLC (37.04%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
TLK Operating Company LLC (37.04%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
TLM Tanklager Management GmbH (49.00%)[a]	Am Tankhafen 4, 4020 Linz, Austria
TLS Tanklager Stuttgart GmbH (45.00%)	Zum Ölhafen 49, 70327 Stuttgart, Germany
Tonatiuh Trading 1 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Torsina Oil Company "TORSINA" (37.50%)	4 Palestine Road, 4th District, New Maadi, Cairo, Egypt
TRaBP GbR (75.00%)[e]	Huestraße 25, 44787, Bochum, Germany
Trafineo GmbH & Co. KG (75.00%)[e]	Wittener Straße 56, Bochum, Germany
Trafineo Service GmbH (75.00%)	Wittener Straße 45, 44789 Bochum, Germany
Trafineo Verwaltungs-GmbH (75.00%)	Wittener Straße 56, Bochum, Germany
Trans Adriatic Pipeline AG (24.57%)	Lindenstrasse 2, 6340 Baar, Switzerland
TransTank GmbH (50.00%)	Am Stadthafen 60, 45881 Gelsenkirchen, Germany
Tricoya Ventures UK Limited (35.56%)	Brettenham House, 19 Lancaster Place, London, WC2E 7EN, United Kingdom
TRTM Inc. (37.04%)	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Tuwale Power Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
TWQE2 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
United Gas Derivatives Company "UGDC" (33.33%)	55 Road 18, Maadi, Cairo, Egypt
United Kingdom Oil Pipelines Limited (33.50%)	5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS, United Kingdom
Ursa Oil Pipeline Company LLC (22.69%)[a]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
VIC CBM Limited (50.00%)	Eni House, 10 Ebury Bridge Road, London, SW1W 8PZ, United Kingdom
Virginia Indonesia Co. CBM Limited (50.00%)	Eni House, 10 Ebury Bridge Road, London, SW1W 8PZ, United Kingdom
Walton-Gatwick Pipeline Company Limited (42.33%)	5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS, United Kingdom
West London Pipeline and Storage Limited (30.50%)	5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS, United Kingdom
West Morgan Petroleum Company (PETROMORGAN) (50.00%)	4 Palestine Road, 4th District, New Maadi, Cairo, Egypt
Wick Farm Grid Limited (21.60%)	Woodwater House, Pynes Hill, Exeter, England, EX2 5WR
Wiri Oil Services Limited (27.78%)	303 Parnell Rd, Parnell, Auckland, New Zealand
Yangtze River Acetyls Co., Ltd (51.00%)[a]	97 Weijiang Road (in the Petrochemical Park), Changshou District, Chongqing, China
Yermak Neftegaz LLC (49.00%)[a]	Kosmodamianskaya nab, 52/3, 115035, Moscow, Russian Federation
Your Power No. 1 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 10 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 19 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 2 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 3 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 8 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Your Power No12 Limited (43.20%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Zubie, Inc. (20.30%)	160 Greentree Drive, Suite 101, Dover, County of Kent DE 19904, United States

[a] Member interest
[b] A and B shares
[c] Common stock and preference shares
[d] Ordinary shares and preference shares
[e] Partnership interest
[f] A, B and D shares
[g] A shares
[h] Interest held directly by BP p.l.c.
[i] 99% held directly by BP p.l.c.
[j] 1% held directly by BP p.l.c.
[k] Ordinary, A and B shares
[l] 0.008% held directly by BP p.l.c.
[m] Ordinary shares and cumulative redeemable preference shares
[n] 79.93% ordinary shares and 99.06% preference shares
[o] Members interest, (49.99%) subordinated units and (4.37%) common units traded on the New York stock exchange
[p] 93.59% ordinary shares and 81.01% preference 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] Ordinary and A shares
[t] Ordinary and deferred shares
[u] Subsidiary undertaking pursuant to sections 1162(2), 1162(3)(b) and Paragraph 6 of Schedule 7 of the Companies Act 2006
[v] 100% ordinary shares and 58.63% preference shares
[w] 92.31% B shares and 78.43% D shares
[x] Preference shares
[y] 15% held directly by BP p.l.c
[z] Unlimited redeemable shares
[α] B shares
[β] 96.52% C shares
[γ] 1.89% A shares and 40.80% B shares
[δ] 43.2% A shares, 43.2% C shares, 43.2% D shares, 43.2% E shares, 43.2% F shares and 43.2% G shares
[ε] 5% held directly by BP p.l.c

The parent company financial statements of BP p.l.c. on pages 238-271 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

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