



Energy with purpose means transforming while performing.

Energy with purpose

BPX Energy: Delivering synergies

We have been transforming BPX Energy, our US onshore oil and gas business, with the purchase of world-class unconventional assets from BHP.

- The acquisition gave us access to some of the best basins in the onshore US, with 487,000 acres of leasehold across a new position in the liquids-rich Permian-Delaware basin, and two positions in the Eagle Ford and Haynesville basins.
- It positions BP as a top producer in the region.

Good progress

Since we began operating the assets, we have delivered synergies of \$240 million in 2019, above our planned target of \$90 million.

Consolidated financial statements of the BP group

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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 2019 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 Financial Reporting Standard (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 the:

- 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 accounting 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 reporting 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 "Reduced Disclosure Framework" (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. The non-audit services provided to the group and parent company for the year are disclosed in note 36 to the financial statements. 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	<p>The key audit matters that we identified in the current year are as follows:</p> <ul style="list-style-type: none"> • Potential impact of climate change and the energy transition (impacting PP&E, goodwill, intangible assets and provisions); • Impairment of upstream oil and gas property, plant and equipment (PP&E) assets; • Impairment of exploration and appraisal assets (included within 'intangible assets' in the Group balance sheet); • Accounting for structured commodity transactions (SCTs) within the integrated supply and trading (IST) function, and the valuation of other level 3 financial instruments (potentially impacting all financial statement accounts, in particular finance debt); • IT controls relating to financial systems (potentially impacting all financial statement accounts); and • Management override of controls (potentially impacting all financial statement accounts).
Changes in our key audit matters since the prior year	<p>These key audit matters are consistent with those we identified in the prior year except that:</p> <ul style="list-style-type: none"> • This year we identified the potential impact of climate change and the energy transition as a key audit matter, given the significant increase in focus on this issue by management and by external stakeholders, and the potential impact on the financial statements as a consequence. • In our report for the year ended 31 December 2018 we identified the accounting for acquisitions and disposals within the upstream segment as a key audit matter, in large part as a consequence of the accounting complexities surrounding the \$10.3 billion acquisition of BHP Billiton assets in the US. During the current year, there were no material acquisitions and there were fewer significant accounting complexities and judgements in the disposal transactions undertaken by BP. Accordingly, we did not identify this as a key audit matter for 2019.
Materiality	<p>We have set materiality for the current year at \$850 million (2018 \$750 million) based on profit before tax, profit before impairment charges and tax, and underlying replacement cost profit before interest and tax.</p>
Scoping	<p>Our scope covered 263 components. Of these, 179 were full-scope audits and the remaining 84 were subject to specific procedures on certain account balances by component audit teams or the group audit team. These covered 81% of group revenue and 75% of PP&E.</p>

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

Conclusions relating to going concern, principal risks and viability statement

Going concern

We have reviewed the directors' statement on page 157 to the financial statements 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 12 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.

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 68-71 that describe the principal risks, procedures to identify emerging risks, and an explanation of how these are being managed or mitigated;
- the directors' confirmation on page 128 that they have carried out a robust assessment of the principal and emerging risks facing the group, including those that would threaten its business model, future performance, solvency or liquidity; or
- the directors' explanation on page 129 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.

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. 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. All of these matters were considered and discussed with the audit committee as described on page 93.

Throughout the course of our audit we identify risks of material misstatement ('risks'). We consider both the likelihood of a risk 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.

Going concern is the basis of preparation of the financial statements that assumes an entity will remain in operation for a period of at least 12 months from the date of approval of the financial statements.

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

Viability means the ability of the company to continue over the time horizon considered appropriate by the directors, which for BP is three years.

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

Potential impact of climate change and the energy transition (impacting PP&E, goodwill, intangible assets and provisions)	
Key audit matter description	How the scope of our audit responded to the key audit matter
<p>Climate change impacts BP's business in a number of ways as set out in the strategic report on pages 2-71 of the Annual Report and Accounts.</p> <p>It represents a strategic challenge with its implications becoming increasingly significant towards 2050 and beyond. Whilst many of BP's oil and gas properties and refining assets are long-term in nature, none are being amortised over a period that extends beyond this date. At current rates of depreciation, depletion and amortisation (DD&A), the average life of the upstream PP&E is seven years and the downstream PP&E is 13 years. Accordingly, the related principal risks that we have identified for our audit are as follows:</p> <ul style="list-style-type: none"> Forecast assumptions used in assessing the value of assets within BP's balance sheet for impairment testing, particularly oil and gas price assumptions relevant to upstream oil and gas PP&E assets, may not appropriately reflect changes in supply and demand due to climate change and the energy transition (see 'impairment of upstream PP&E' below); Recoverability of exploration and appraisal (E&A) assets included within BP's balance sheet where the investment required in order to develop particular projects into producing oil and gas PP&E assets might not be sanctioned by the board in future due to climate change considerations or a potential development may not be considered to be economic due to the impact of climate change and the energy transition on oil and gas prices (see 'impairment of exploration and appraisal assets' below) <p>Management also assessed the following potential risks that could arise from climate change considerations.</p> <ul style="list-style-type: none"> The carrying value of goodwill may no longer be recoverable and therefore may need to be impaired; The useful economic lives of the group's PP&E may be shortened as society moves towards 'net zero' emissions targets, such that the DD&A charge is materially understated; Decommissioning and asset retirement obligations may need to be brought forward with a resulting increase in the present value of the associated liabilities; and Climate change-related litigation brought against BP, as disclosed in Note 33 to the financial statements and described on page 320 under legal proceedings, may lead to an outflow of funds requiring provision in the current year. <p>The material upstream goodwill balance is recorded and tested at the segment level. The most significant assumption in the goodwill impairment test affected by climate change relates to future oil and gas prices (see 'impairment of upstream PP&E' below). Given the significant headroom in the goodwill impairment test, management identified no other assumption that could lead to a material misstatement of goodwill due to the energy transition and other climate change factors. Disclosures in relation to sensitivities for goodwill are included within Note 14 on pages 187-188.</p> <p>The downstream segment has a goodwill balance at 31 December 2019 of \$3.9 billion, of which the most significant element is \$2.8 billion relating to the Lubricants business. Notwithstanding the expected global transition to electric vehicles, management noted that demand for lubricants is forecast to continue to grow until at least 2040, underpinning the substantial headroom in the most recent impairment test as described in Note 14.</p> <p>As described on pages 70-71 and in Note 1, the impact of potential changes in DD&A charges, or to decommissioning dates would not have a material impact on the amounts reported in the current period.</p> <p>The above considerations were a significant focus of management during the period which led to this being a matter that we communicated to the audit committee, and which had a significant effect on the overall audit strategy. We therefore identified this as a key audit matter.</p>	<p>Overall response</p> <p>We held discussions with management, with Deloitte specialists and within the Group engagement team to identify the areas where we felt climate change could have a potential impact on the financial statements.</p> <p>We also established a climate change steering committee comprising a group of senior partners with specific sustainability and technical audit and accounting expertise within Deloitte to provide an independent challenge to our key decisions and conclusions with respect to this area.</p> <p>Audit procedures in respect of impairment of upstream oil and gas PP&E assets and exploration and appraisal assets</p> <p>The audit response related to the two principal risks identified is set out under the key audit matters for impairment of upstream oil and gas PP&E assets on pages 135-136 and the impairment of exploration and appraisal assets on page 137.</p> <p>Other audit procedures performed</p> <p>We challenged management's assertion that the impact of potential changes in DD&A charges, or to decommissioning dates, would not have a material impact on the amounts reported in the current period, by making inquiries of relevant BP personnel outside the finance function, reviewing internal and external documents and conducting sensitivity analysis as part of our audit risk assessment procedures. We obtained third party forecasts of future refined petroleum product demand for those countries which are included in our group full audit scope for downstream, under a range of scenarios including scenarios noted as being consistent with achieving the 2015 COP 21 Paris agreement goal to limit temperature rises to well below 2°C ('Paris 2°C Goal'). These indicated that global demand for such products was expected to remain significant until at least 2040.</p> <p>We performed procedures to satisfy ourselves that, other than future oil and gas price assumptions, there were no other assumptions in management's goodwill calculations to which reasonably possible changes could cause goodwill to be materially misstated.</p> <p>We obtained an understanding of the controls identified by management as being relevant to ensuring the completeness and accuracy of litigation and climate change related disclosure within the Annual Report; we performed procedures to test these controls.</p> <p>With regard to climate change litigation, we designed procedures specifically to respond to the risks that provisions could be understated or that contingent liability disclosures may be omitted or be inaccurate including:</p> <ul style="list-style-type: none"> Holding discussions with the group general counsel and other senior BP lawyers regarding climate change matters; Conducting a search for climate change litigation and claims brought against the group; and Making written inquiries of, and holding discussions with, external legal counsel advising BP in relation to climate change litigation. <p>We read the other information included in the Annual Report and considered (a) whether there was any material inconsistency between the other information and the financial statements; or (b) whether there was any material inconsistency between the other information and our understanding of the business based on audit evidence obtained and conclusions reached in the audit.</p>

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

Key observations	<p>Key observations in relation to oil and gas price assumptions used in upstream oil and gas PP&E assets impairment tests, and the recoverability of exploration and appraisal assets including the impacts of climate change, are set out in the relevant key audit matter below.</p> <p>Based on the audit evidence obtained both from internal and external legal counsel, we were satisfied with management's assertion that no provision should currently be made in respect of climate change litigation. We reviewed management's disclosure of the contingent liabilities in respect of these matters and concluded that the disclosures are appropriate.</p> <p>We were satisfied with the results of our procedures relating to DD&A charges, goodwill and decommissioning.</p> <p>We are satisfied that management's other disclosures in the Annual Report relating to climate change are consistent with the financial statements and our understanding of the business.</p>
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Impairment of upstream oil and gas property, plant and equipment (PP&E) assets	
Key audit matter description	How the scope of our audit responded to the key audit matter
<p>The group balance sheet includes property, plant and equipment (PP&E) of \$133 billion (2018 \$135 billion), of which \$90 billion (2018 \$99 billion) is oil and gas properties within the upstream segment.</p> <p>Management announced an approximately \$10 billion disposal programme for 2019 and 2020. As a consequence of this, certain assets identified for disposal have been assessed for impairment in the context of their fair value based on the expected disposal proceeds from third parties, as opposed to their value in use.</p> <p>The transition to a lower carbon global economy may potentially lead to a lower oil and gas price scenario in the future due to declining demand. Management took into account considerations of uncertainty over the pace of the transition to lower-carbon supply and demand and the social, political and environmental actions that will be taken to meet the goals of the Paris climate change agreement when determining their future oil and gas price assumptions and revised the future price assumptions downwards when compared with the prior year assumptions as set out in Note 1 on page 162. As a consequence, they identified a risk of impairment across all upstream CGUs.</p> <p>Accordingly, as required by International Accounting Standard (IAS) 36 'Impairment of Assets', management performed a review of all the upstream cash generating units (CGUs) for indicators of impairment and impairment reversal as at 31 December 2019. Further information has been provided in Note 1.</p> <p>In large part due to the disposal programme, for the year ended 31 December 2019, BP recorded \$5,871 million (2018 \$400 million) of upstream impairment charges and \$129 million (2018 \$580 million) of impairment reversals. Through our risk assessment procedures, we have determined that there are three key estimates in management's determination of the level of impairment charge/reversal to record. These are:</p> <ul style="list-style-type: none"> • Oil and gas prices - BP's oil and gas price assumptions have a significant impact on CGU impairment assessments and valuations performed across the portfolio, and are inherently uncertain. Furthermore, as noted above the estimation of future oil and gas prices is subject to increased uncertainty, given climate change and the global energy transition. There is a risk that management's oil and gas price assumptions are not reasonable, leading to a material misstatement. The assumptions are highly judgemental. 	<p>We tested management's internal controls over the setting of oil and gas prices, discount rates and reserve estimates, as well as the controls over the performance of the impairment valuation tests. In addition, we conducted the following substantive procedures.</p> <p>Oil and gas prices</p> <ul style="list-style-type: none"> • We independently developed a reasonable range of forecasts based on external data obtained, against which we compared the company's future oil and gas price assumptions in order to challenge whether they are reasonable. • In developing this range we obtained a variety of reputable third party forecasts, peer information and market data. • In challenging management's price assumptions, we considered the extent to which they and each of the forecast pricing scenarios obtained from third parties reflect the impact of lower oil and gas demand due to climate change. We specifically reviewed third party forecasts stated as being, or interpreted by us as being, consistent with achieving the Paris 2°C Goal and considered whether they presented contradictory evidence. • We reviewed and challenged management's disclosures including in relation to the sensitivity of oil and gas price assumptions to reduced demand scenarios whether due to climate change or other reasons. <p>Discount rates</p> <ul style="list-style-type: none"> • We independently evaluated BP's discount rates used in impairment tests with input from Deloitte valuation specialists. • We assessed whether country risks and tax adjustments were appropriately reflected in BP's discount rates. <p>Reserves estimates</p> <ul style="list-style-type: none"> • We reviewed BP's reserves estimation methods and policies, assisted by Deloitte reserves experts. • We assessed, with the assistance of Deloitte reserves experts, how these policies had been applied to a sample of internal reserves estimates. • We reviewed reports provided by external experts and assessed their scope of work and findings.

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Impairment of upstream oil and gas property, plant and equipment (PP&E) assets (continued)	
Key audit matter description	How the scope of our audit responded to the key audit matter
<ul style="list-style-type: none"> • Discount rates - Given the long timeframes involved, certain recoverable amounts of assets 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. <p>We identified and focused on certain individual CGUs with a total carrying value of \$12.3 billion (2018 \$21.8 billion) which we determined would be most at risk of a material impairment as a result of a reasonably possible change in the key assumptions, particularly the oil and gas price assumptions. Accordingly, we identified these as a significant audit risk. We also focused on assets with a further \$33.4 billion (2018 \$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 to the consolidated financial statements.</p>	<ul style="list-style-type: none"> • We assessed the competence, capability and objectivity of BP's internal and external reserve experts, through obtaining their relevant professional qualifications and experience. • We compared hydrocarbon production forecasts used in impairment tests to estimates and reports and our understanding of the life of fields. • We performed a retrospective review to check for indications of estimation bias over time. <p>Other procedures</p> <ul style="list-style-type: none"> • We challenged management's cash generating unit determination and considered whether there was any contradictory evidence present. • We validated that BP's asset impairment methodology was appropriate and tested the integrity of impairment models. • Where relevant, we also assessed management's historical forecasting accuracy and whether the estimates had been determined and applied on a consistent basis across the group. <p>Since 31 December 2019, the oil price has fallen sharply in large part due to the impact of the international spread of COVID-19 (Coronavirus) and geopolitical factors. As part of our post balance sheet audit procedures we considered whether these events provide evidence of conditions that existed at the balance sheet date.</p>
<p>Key observations</p>	<p>Oil and gas prices</p> <p>The long-term oil and gas price assumptions used to determine recoverable amount through value-in-use impairment tests are derived from the central case long term price assumption used for investment appraisal purposes (as set out on page 19) and represent management's best estimate of future prices as set out in Note 1. We determined that BP's oil and gas price assumptions are reasonable when compared against the range of third party forecasts we identified as being appropriate for the purpose. In forming this view, we included each forecaster's 'best case', 'central case' or 'most likely' estimate.</p> <p>For the purpose of PP&E impairment tests, management is required under IAS 36 to apply its current 'best estimate' of future oil and gas prices.</p> <p>We observed that, as well as publishing a 'best case', 'central case' or 'most likely' estimate, the majority of third party price forecasters publish a number of other future scenarios under different plausible economic assumption sets, and that the price forecasts stated as being or interpreted by us as being 'Paris 2°C Goal' scenarios were the lowest of all scenarios from those forecasters. We observed that for oil, all the prices in third party 'Paris 2°C Goal' scenarios in our sample were lower than BP's oil price assumption from 2023 onwards, and for gas, BP's price assumptions for impairment purposes were close to the highest 'Paris 2°C Goal' scenario.</p> <p>While these 'Paris 2°C Goal' scenarios indicate that BP's price assumptions for impairment purposes are not consistent with the world being on a path to achieving the Paris 2°C Goal we observed that none of those third party forecasters described their 'Paris 2°C Goal' scenarios as their 'best case', 'central case' or "most likely" estimate.</p> <p>We reviewed the disclosures included in Note 1 to the accounts in respect of price assumptions, including the sensitivity analysis presented therein. We observed that the second downside sensitivity, in which prices start 15% lower than the best estimate and gradually reduce to 25% lower than the best estimate by 2040, is within the range of third party Paris 2°C Goal forecasts both for oil and for gas albeit towards the upper end for oil.</p> <p>We are satisfied that the COVID-19 outbreak and the geopolitical factors are both non-adjusting events and accordingly the recent sharp fall in the oil price is a result of conditions that arose after the balance sheet date. As such we concluded that management's future oil and gas price assumptions used in impairment tests to assess the recoverable amount of assets at the balance sheet date should not be adjusted.</p> <p>Discount rates</p> <p>BP's post-tax nominal 6% weighted average cost of capital, used as the starting point for setting discount rates used for impairment testing, was within the independent range calculated by our Deloitte valuation specialists.</p> <p>We were also satisfied with the calculation of country risk premia. When the rates were grossed up for tax as required for impairment testing the rates for a small number of countries fell outside of our reasonable range but there was an insignificant impact in respect of a small number of CGUs. Accordingly, we are satisfied with the discount rates used in the impairment testing.</p>

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Key observations	<p>We reviewed the disclosures included in Note 1 to the accounts in respect of discount rate assumptions used and confirmed that they are consistent with the IFRS disclosure requirements.</p> <p>Reserves estimates</p> <p>We concluded that the assumptions used to derive the estimates were reasonable.</p>
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Impairment of exploration and appraisal assets (included within intangible assets within the Group balance sheet)	
Key audit matter description	How the scope of our audit responded to the key audit matter
<p>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 2019, \$14 billion (2018 \$16 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.</p> <p>There is a significant judgement relating to the 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.</p> <p>Furthermore, similar to upstream PP&E assets discussed above, E&A assets are also potentially exposed to climate change and the global energy transition. A greater number of projects may be expected not to proceed as a consequence of lower forecast future demand, lower appetite by management and the board to allocate capital to certain projects, or increased objections from stakeholders to the development of certain projects. In response, management has updated its internal controls over its IFRS 6 assessment to reflect the potential impact that climate change and the energy transition may have on E&A assets.</p> <p>In the prior year audit, we had identified this key audit matter as a significant risk primarily on account of uncertainty arising from the potential inability of the Company to secure key license extensions in respect of assets in the Gulf of Mexico and on three licenses in other regions.</p> <p>During the current year, and subsequent to the year end, management have obtained licence extensions in the Gulf of Mexico and other regions such that we have concluded this no longer represents a significant audit risk. Nevertheless, given the inherent uncertainty associated with the development and deployment of these assets, we still consider this area to be a higher risk.</p>	<p>We obtained an understanding of the group's E&A impairment assessment processes and tested management's internal controls, including the new control procedures implemented to address potential climate change considerations.</p> <p>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 current period risk of impairment (e.g. new information from exploration activities, or imminent licence expiry).</p> <p>We performed a retrospective review of impairment charges recorded in the period, and assessed whether impairment charges were timely.</p> <p>We reviewed and challenged management's significant IFRS 6 impairment judgements, having regard to the impairment criteria of IFRS 6 and BP's accounting policy. We verified key facts relevant to significant carrying amounts (by obtaining for example evidence of future E&A plans and budgets, and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms).</p> <p>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 agreeing 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 the development of any projects would be inconsistent with the elements of BP's current strategy which are designed to ensure it is resilient to the energy transition and climate change considerations or which would otherwise have a prohibitively high environmental or social impact for the directors to sanction the necessary investment.</p>
Key observations	<p>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.</p> <p>Where E&A costs were carried in respect of projects where licences had previously expired, we obtained evidence that these licences have been renewed.</p> <p>We also confirmed management's view that they did not consider that the development of any of their E&A assets is inconsistent with BP's current strategy. In that context we particularly considered the Canadian oil sands assets (see Note 1) and concluded that, given low-carbon extraction technologies required to optimise the development of these assets are being researched, continuing to carry the assets was consistent with IFRS6.</p>

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 (potentially impacting all financial statement accounts, in particular finance debt)

Key audit matter description	How the scope of our audit responded to the key audit matter
<p>In the normal course of business, 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.</p> <p><i>Accounting for structured commodity transactions:</i> 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:</p> <ul style="list-style-type: none"> 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. <p>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.</p> <p>Accounting for SCTs is often complex and involves significant judgement, as these transactions often feature multiple elements that will have a material impact on the presentation and disclosure of these transactions in the financial statements and on key performance measures, including in particular classification of liabilities as finance debt. We have identified the accounting for SCTs as a significant audit risk.</p> <p><i>Level 3 financial instruments:</i> 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 complex 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.</p> <p>As at 31 December 2019, the group's total financial assets and liabilities measured at fair value were \$12.5 billion (2018 \$12.8 billion) and \$8.8 billion (2018 \$8.9 billion), of which level 3 derivative financial assets were \$5.3 billion (2018 \$3.6 billion) and level 3 derivative financial liabilities were \$4.4 billion (2018 \$3.1 billion).</p>	<p>Accounting for structured commodity transactions:</p> <p>For structured commodity transactions, we performed audit procedures to:</p> <ul style="list-style-type: none"> • Test controls related to the transactions. • Develop an understanding of the commercial rationale of the transactions through review of transaction support documents and executed agreements, and discussions with management. • Perform a detailed accounting analysis for a sample of structured commodity transactions involving significant day 1 profits, deferred working capital arrangements, offtake arrangements and/or commitments. <p>To assess the appropriateness of the accounting treatment of SCTs, we embedded technical accounting specialists within the audit team. During the year we identified two new SCTs which were subjected to our audit procedures listed above. We also reconsidered the SCTs which were identified during 2018 and which have been subject to ongoing assessment in 2019.</p> <p>Other level 3 financial instruments:</p> <p>To address the complexities associated with auditing the value of level 3 financial instruments, the engagement 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:</p> <ul style="list-style-type: none"> • We tested 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. <p>We performed substantive valuation testing procedures at interim and year-end balance sheet dates, including:</p> <ul style="list-style-type: none"> • Engaging a Deloitte valuations specialist to develop fair value estimates, using independently sourced inputs where these were available, and challenge 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. In situations where we utilised management's inputs, these were compared to external data sources to ensure they were reasonable; • Evaluating management's valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period; and • Comparing management's input assumptions against the expected assumptions of other market participants and observable market data.
<p>Key observations</p>	<p>We reviewed the features of the SCTs and determined that the accounting adopted for each of these was appropriate and in accordance with IFRS.</p> <p>We concluded that management's valuations relating to level 3 instruments were appropriate.</p> <p>We did not identify any indications of fraudulent misrepresentation of revenue recognition in the transactions, valuation estimates or accounting entries that we tested.</p>

IT controls relating to financial systems (potentially impacting all financial statement accounts)	
Key audit matter description	How the scope of our audit responded to the key audit matter
<p>The group's financial systems environment is complex, with 121 separate systems scoped as being relevant for the group audit.</p> <p>Due to the reliance on financial systems within the group, IT controls which support these systems are critical to maintaining an effective control environment.</p> <p>We identified IT control deficiencies in two key areas.</p> <p>User Access Management: In the prior year, we identified a number of deficiencies relating to user access management, both within the group and at the group's IT service organizations (together 'access deficiencies'). Management commenced the implementation of a remediation programme in the prior year, although this programme extends into 2020.</p> <p>During our 2019 audit we identified a number of additional deficiencies relating to user access management in the IT environment as a result of new systems in scope, the control of highly privileged finance access and the management of segregation of duties.</p> <p>The access deficiencies identified increase the risk that individuals across BP had inappropriate access during the period. This results in an increased risk that data and reports from the affected systems are not reliable. The access deficiencies impact all components within the scope of our group audit.</p> <p>Management remediated some of the deficiencies during 2019. For the remaining deficiencies, management implemented mitigating controls to confirm that no inappropriate access had been exploited.</p> <p>Change Management: A new change management process and change control ticketing system, ServiceNow, was implemented for 2019. Following the change in process and tool a number of deficiencies were identified by Deloitte and by management around the consistent implementation of the minimum change management controls.</p> <p>The change management deficiencies identified increase the risk of inappropriate or untested changes being made which could negatively impact the way a system operates and accordingly, the ongoing integrity of the controls, reports and data within key financial systems.</p> <p>In responding to the identified deficiencies management have implemented retrospective approvals for all exceptions identified. Management also performed a full review of all changes made to all systems in the scope of our group audit to ensure all changes were appropriate and that change management controls were documented. In addition management established a programme to remediate all the identified deficiencies.</p> <p>The change management issues identified impact all components within the scope of our group audit.</p> <p>Both the user access management controls and the controls over the management of system change 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 the risks addressed by the control.</p>	<p>We obtained an understanding of management's processes and relevant financial systems, and tested the associated general IT controls and automated business controls. We also tested the integrity of key reports. This testing led us to identify a number of deficiencies, notably in relation to user access and change management.</p> <p>User Access Management: In responding to the identified deficiencies in user access, our IT audit specialists performed procedures to:</p> <ul style="list-style-type: none"> • Test the controls that management has implemented or re-designed in order to remediate the deficiencies; • Assess and test the mitigating controls that management identified, including directly testing those controls operated by IT service organizations; 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 test controls implemented by management to identify instances of the use of inappropriate access. <p>Change Management: In responding to the identified deficiencies our IT audit specialists performed independent testing over:</p> <ul style="list-style-type: none"> • The mitigating controls performed by management; and • Key automated business controls and the logic and accuracy of key reports to ensure no changes had impacted their effectiveness. <p>These procedures were designed to address the likelihood and impact of inappropriate or untested changes being implemented.</p>
Key observations	<p>Our testing confirmed that the remediated controls were operating effectively.</p> <p>Our testing of the mitigating controls management performed, alongside our independent testing to demonstrate whether the access and change management deficiencies were exploited during the year, did not identify instances of inappropriate access usage or change implementation.</p> <p>Accordingly, we were satisfied with the results of the remediation to date and the mitigation such that we continued to adopt an audit approach which places reliance on the operating effectiveness of financial controls. Under our methodology, this enables us to apply lower sample sizes in our substantive testing.</p> <p>Management continues to work to remediate fully the access and change management deficiencies identified.</p>

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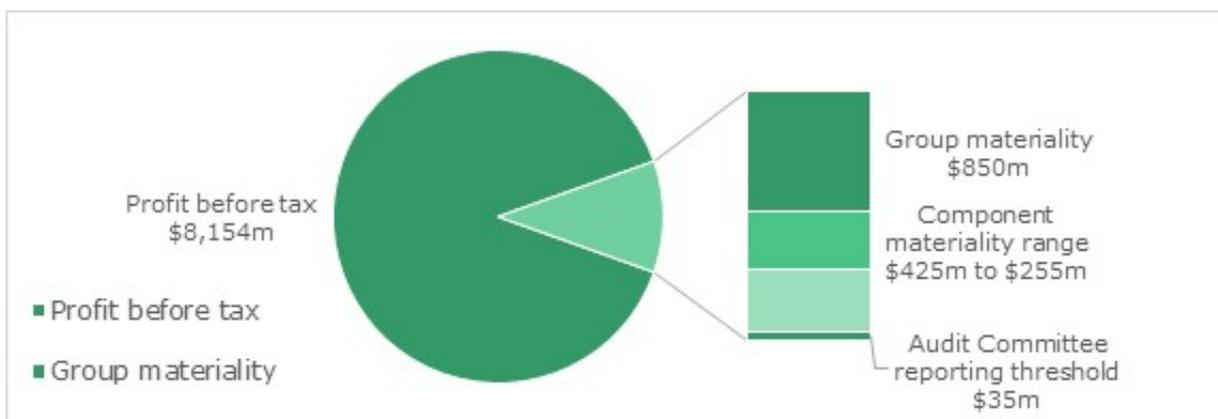
Management override of controls (potentially impacting all financial statement accounts)	
Key audit matter description	How the scope of our audit responded to the key audit matter
<p>We conducted an assessment of the fraud risks arising from management override of controls by considering potential areas where the group's financial statements could be manipulated, including:</p> <ul style="list-style-type: none"> • Inappropriate accounting estimates and judgements; and • Accounting for significant unusual transactions arising from changes to the business. <p>In performing this assessment we considered 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.</p> <p>During our 2018 audit we identified control deficiencies relating to the posting of accounting journal entries at the components where testing was performed. These control deficiencies remain as of the end of 2019 and extended to other components where testing was performed. There were also other changes to BP's processes for the posting of certain journals which created further deficiencies. As in the previous year, management directed us to other compensating controls which they considered to mitigate the risks, which we subsequently tested. Management has initiated a remediation programme which will extend into 2020.</p> <p>This had a significant bearing again this year on the allocation of resources in the audit, and the direction of effort of the audit team globally and was a matter we discussed with the audit committee. Accordingly, we identified this as a key audit matter.</p>	<p>We tested the relevant primary and, where necessary, compensating controls that management identified as responding to the risk of fraudulent journal entries.</p> <p>In addition, we:</p> <ul style="list-style-type: none"> • 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. <p>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:</p> <ul style="list-style-type: none"> • 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. <p>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.</p> <p>The risks and responses to the revenue recognition risks within the integrated supply and trading function are set out on page 138.</p>
Key observations	<p>The nature of the identified deficiencies over journal entry controls varies from business to business, so there is no single root cause. Management identified compensating controls to mitigate the risk associated with the design deficiencies identified. These included low-level analytical reviews, controls over closing balances, period-end analytical review controls and certain automated business controls. Our testing of these compensating controls concluded they were, in combination, appropriately designed and implemented and that they were operating effectively for the year.</p> <p>Our substantive testing of journal entries and other adjustments, selected through the use of our data analytics tools, did not identify any inappropriate items.</p> <p>We did not identify evidence of overall bias or any significant and 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.</p> <p>Management is continuing to design and implement appropriate process level controls over journal entries in 2020.</p>

Our application of materiality

We define materiality as the magnitude of misstatement in the financial statements that makes it probable that the economic decisions of a reasonably knowledgeable person would be changed or influenced. 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:

	Group financial statements	Parent company financial statements
Materiality	Materiality has been set at \$850 million for the current year. In 2018, we used a materiality of \$750 million. The increase is partly due to BP's financial performance in 2019 and also the fact that our 2018 materiality level reflected some conservatism in our first year as auditor.	Materiality has been set at \$1,200 million for the current year. (2018 \$1,200 million)
Basis for determining materiality	We considered a number of metrics when determining group materiality, including profit before taxation, profit before impairment charges and taxation and underlying replacement cost profit before interest and taxation. Our selected materiality figure represents 10.3% of profit before taxation, 5.7% of profit before impairment charges and taxation, and 5.0% of underlying replacement cost profit before interest and taxation. In 2018, we determined materiality to be \$750m which represented 4.5% of profit before taxation and 3.2% of underlying replacement cost profit before interest and taxation. The significant impairment charges of \$6,847m recognized in 2019 caused us to place more emphasis on profit before impairment charges and taxation in our determination of materiality this year.	We determined materiality for our audit of the standalone parent using 1% (2018 1%) of net assets.
Rationale for the benchmark applied	<p>We conducted an assessment of which line items are 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.</p> <p>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, or where the impact of price volatility may result in material impairment charges or reversals in a particular year. The significant impairment charges recognized in 2019 caused us to place more emphasis on profit before impairment charges and taxation this year.</p> <p>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.</p>	<p>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 parent company 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.</p> <p>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.</p>



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Performance materiality

We set performance materiality at a level lower than materiality to reduce the probability that, in aggregate, uncorrected and undetected misstatements exceed the materiality for the financial statements as a whole. Group performance materiality was set at 60% of group materiality for the 2019 audit (2018 50%). The increase was due to performance materiality being set at a conservative level for 2018, given it was our first year as auditor, and to reflect our increased knowledge of the business.

Error reporting threshold

We agreed with the audit committee that we would report to the committee all audit differences in excess of \$35 million (2018 \$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

Identification and scoping of components

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.

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 our 2018 audit engagement.

Our audit approach was generally to place reliance on management's controls over financial reporting.

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 179 reporting consolidation units ('cons units' or components) (2018 108) which were selected based on their size or risk characteristics. The primary reason for the change in scope is a change in our approach to the global audit of the IST function. We also added to our full scope audit components for 2019 the new businesses acquired in onshore US in 2018 from BHP. Our full-scope audits are in the UK, US, 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, component teams performed audit procedures on specified account balances for 55 cons units (2018 16) also covering operations in Angola, Alaska, Trinidad & Tobago and Australia. The group engagement team performed audit procedures on specified account balances by segment teams to component materiality, with certain additional specific procedures performed by component teams, covering an additional 29 cons units (2018 12).

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.

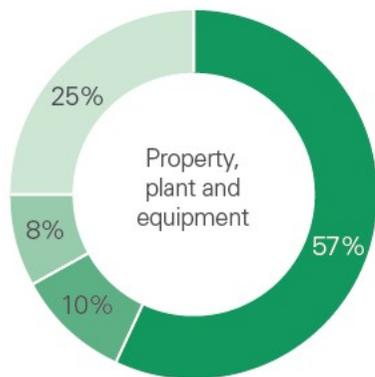
The remaining components are not significant individually and include many small, low risk components and balances. On average, they each represent 0.03% of group revenue (2018 0.06%) and 0.03% of property, plant and equipment (2018 0.08%). For these components, we performed other procedures, including 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.

Working with other auditors

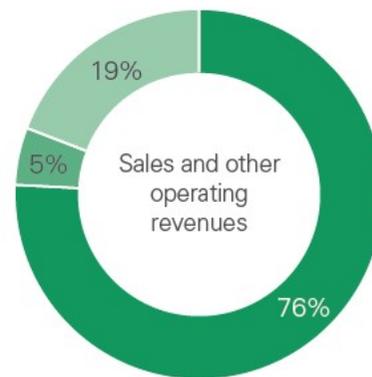
The group audit team provides direct oversight, review, and coordination of our component audit teams. The group audit team interacted regularly with the component Deloitte teams during each stage of the audit, were responsible for the scope and direction of the audit process and reviewed key working papers. We maintained continuous and open dialogue with our component 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 conducted visits to meet with the component teams responsible for all of the full scope locations during the year as well as Egypt, Trinidad & Tobago, and key Global Business Services (GBS) accounting locations. 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. In addition, a global audit planning meeting was held in London for two days in July led by the senior statutory auditor and involving the group audit team, partners and staff from all full scope component teams, audit teams responsible for testing at key GBS locations, senior management from BP, and the audit committee chairman.

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.



● Full audit scope	57%
● Specified account balances	10%
● Specific audit procedures	8%
● Review at group level	25%



● Full audit scope	76%
● Specified account balances	5%
● Review at group level	19%

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.

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.

We have nothing to report in respect of these matters.

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 users taken on the basis of these financial statements.

Details of the extent to which the audit was considered capable of detecting irregularities, including fraud and non-compliance with laws and regulations are set out below.

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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, we considered the following:

- Our meetings throughout the year with the Group Head of Ethics and Compliance and reviews of BP's internal ethics and compliance reporting summaries, including those concerning investigations;
- Enquiries 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; and
 - the internal controls established to mitigate risks related to fraud or non-compliance with laws and regulations;
- The group's remuneration policies, key drivers for remuneration and bonus levels; and
- Discussions 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 Financial Advisory 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 discussions.

In common with all audits under ISAs (UK), we are also required to perform specific procedures to respond to the risk of management override.

We also obtained an understanding of the legal and regulatory framework that the group operates in, focusing on provisions of those laws and regulations that had a direct effect on the determination of material amounts and disclosures in the financial statements. The key laws and regulations we considered in this context included 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 provisions of other laws and regulations that do not have a direct effect on the financial statements but compliance with which may be fundamental to the group's ability to operate or to avoid a material penalty. These included the group's operating licences, environmental regulations etc.

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 fraud or non-compliance with laws and regulations. We did identify two key audit matters relating to fraud risks, as described above, being the accounting for SCTs and Level 3 instruments within IST, and management override of controls. The key audit matters section of our report explains the matters in more detail and also describes the specific procedures we performed in response to those key audit matters.

In addition to the above, our procedures to respond to risks identified included the following:

- Reviewing the financial statement disclosures and testing to supporting documentation to assess compliance with provisions of relevant laws and regulations described as having a direct effect on the financial statements;
- Enquiring of management, the audit committee, and both internal and external 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 relevant tax authorities including HMRC and IRS; 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 2019, shareholders resolved at the annual general meeting to reappoint Deloitte as auditor from the conclusion of the meeting until the conclusion of the annual general meeting to be held in 2020 and authorized the directors to set the audit fees.

The first accounting period we audited was the 12 month period 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 two years.

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
18 March 2020

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 consolidated group balance sheets of BP p.l.c. (the company) and subsidiaries (together the group) as at 31 December 2019 and 2018, and the related consolidated group income statements, group statements of comprehensive income, group statements of changes in equity, and group cash flow statements, for each of the two years in the period ended 31 December 2019, and the related notes as well as the legal proceedings described on pages 319-320 (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 the group as at 31 December 2019 and 2018, and the results of its operations and its cash flows for each of the two years in the period ended 31 December 2019, 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 group's internal control over financial reporting as of 31 December 2019, 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 18 March 2020 expressed an unqualified opinion on the group's internal control over financial reporting.

Basis for opinion

These financial statements are the responsibility of the group's management. Our responsibility is to express an opinion on the group's 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 the group 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 audit provides a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the group financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the group financial statements and (2) involved especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Throughout the course of our audit we identify risks of material misstatement ('risks'). We consider both the likelihood of a risk 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.

Impairment of upstream oil and gas property, plant and equipment (PP&E) assets - Notes 1 and 12 to the financial statements

Critical Audit Matter Description

The group balance sheet includes property, plant and equipment (PP&E) of \$133 billion, of which \$90 billion is oil and gas properties within the upstream segment.

Management announced an approximately \$10 billion disposal programme for 2019 and 2020. As a consequence of this, certain assets identified for disposal have been assessed for impairment in the context of their fair value based on the expected disposal proceeds from third parties, as opposed to their value in use.

The transition to a lower carbon global economy may potentially lead to a lower oil and gas price scenario in the future due to declining demand. Management took into account considerations of uncertainty over the pace of the transition to lower-carbon supply and demand and the social, political and environmental actions that will be taken to meet the goals of the Paris climate change agreement when determining their future oil and gas price assumptions and revised the future price assumptions downwards when compared with the prior year assumptions as set out in Note 1 on page 162. As a consequence, they identified a risk of impairment across all upstream CGUs.

Accordingly, as required by International Accounting Standard (IAS) 36 'Impairment of Assets', management performed a review of all the upstream cash generating units (CGUs) for indicators of impairment and impairment reversal as at 31 December 2019. Further information has been provided in Note 1.

In large part due to the disposal programme, for the year ended 31 December 2019 BP recorded \$5,871 million of upstream impairment charges and \$129 million of impairment reversals. Through our risk assessment procedures, we have determined that there are three key estimates in management's determination of the level of impairment charge/reversal to record. These are:

- a. **Oil and gas prices**- BP's oil and gas price assumptions have a significant impact on CGU impairment assessments and valuations performed across the portfolio, and are inherently uncertain. Furthermore, as noted above the estimation of future oil and gas prices is subject to increased uncertainty, given climate change and the global energy transition. There is a risk that management's oil and gas price assumptions are not reasonable, leading to a material misstatement. The assumptions are highly judgemental.
- b. **Discount rates**- Given the long timeframes involved, certain recoverable amounts of assets 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.
- c. **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.

We identified and focused on certain individual CGUs with a total carrying value of \$12.3 billion which we determined would be most at risk of a material impairment as a result of a reasonably possible change in the key assumptions, particularly the oil and gas price assumptions. Accordingly, we identified these as a significant audit risk. We also focused on assets with a further \$33.4 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 to the consolidated financial statements.

How the Critical Audit Matter was addressed in the Audit

We tested management's internal controls over the setting of oil and gas prices, discount rates and reserve estimates, as well as the controls over the performance of the impairment valuation tests. In addition, we conducted the following substantive procedures.

Oil and gas prices

- We independently developed a reasonable range of forecasts based on external data obtained, against which we compared the company's future oil and gas price assumptions in order to challenge whether they are reasonable.
- In developing this range we obtained a variety of reputable third party forecasts, peer information and market data.
- In challenging management's price assumptions, we considered the extent to which they and each of the forecast pricing scenarios obtained from third parties reflect the impact of lower oil and gas demand due to climate change. We specifically reviewed third party forecasts stated as being, or interpreted by us as being, consistent with achieving the 2015 COP 21 Paris agreement goal to limit temperature rises to well below 2°C (Paris 2°C Goal).
- We reviewed and challenged management's disclosures including in relation to the sensitivity of oil and gas price assumptions to reduced demand scenarios whether due to climate change or other reasons.

Discount rates

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

Reserves estimates

- We reviewed BP's reserves estimation methods and policies, assisted by Deloitte reserves experts.
- We assessed, with the assistance of Deloitte reserves experts, how these policies had been applied to a sample of 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.
- We compared hydrocarbon production forecasts used in impairment tests to estimates and reports and our understanding of the life of fields.
- We performed a retrospective review to check for indications of estimation bias over time.

Other procedures

- We challenged management's CGU determination, and considered whether there was any contradictory evidence present.
- We validated that BP's asset impairment methodology was appropriate and tested the integrity of impairment models.
- Where relevant, we also assessed management's historical forecasting accuracy and whether the estimates had been determined and applied on a consistent basis across the group.

Since 31 December 2019, the oil price has fallen sharply in large part due to the impact of the international spread of COVID-19 (Coronavirus) and geopolitical factors. As part of our post balance sheet audit procedures we considered whether these events provide evidence of conditions that existed at the balance sheet date.

Impairment of exploration and appraisal assets (included within 'intangible assets' within the group balance sheet) - Notes 1 and 15 to the financial statements

Critical Audit Matter Description

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 2019, \$14 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 significant judgement relating to the 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.

Furthermore, similar to upstream PP&E assets discussed above, E&A assets are also potentially exposed to climate change and the global energy transition. A greater number of projects may be expected not to proceed as a consequence of lower forecast future demand, lower appetite by management and the board to allocate capital to certain projects, or increased objections from stakeholders to the development of certain projects.

During the current year, and subsequent to the year end, management have obtained license extensions in the Gulf of Mexico and other regions where licenses had previously expired such that we have concluded this does not represent a significant audit risk. Nevertheless, given the inherent uncertainty associated with the development and deployment of these assets, we still consider this area to be a higher risk.

How the Critical Audit Matter was addressed in the Audit

We obtained an understanding of the group's E&A impairment assessment processes and tested management's internal controls,

including the controls addressing potential climate change considerations.

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 current period risk of impairment (e.g. new information from exploration activities, or imminent licence expiry).

We performed a retrospective review of impairment charges recorded in the period, and assessed whether impairment charges were timely.

We reviewed and challenged management's significant IFRS 6 impairment judgements, having regard to the impairment criteria of IFRS 6 and BP's accounting policy. We verified key facts relevant to significant carrying amounts (by obtaining for example evidence of future E&A plans and budgets, and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms).

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 agreeing 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 the development of any projects would be inconsistent with the elements of BP's current strategy which are designed to ensure it is resilient to the energy transition and climate change considerations or which would otherwise have a prohibitively high environmental or social impact for the directors to sanction the necessary investment.

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 (potentially impacting all financial statement accounts, in particular finance debt) - Notes 1, 20, 22, 29 and 30 to the financial statements

Critical Audit Matter Description

In the normal course of business, 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:

- Two or more counterparties with non-standard contractual terms;
- Multiple commodity-based transactions; and/or
- 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 inputs when determining their fair value, in which case they will be classified as level 3 financial instruments under IFRS 13, 'Fair Value Measurement'.

Accounting for SCTs is often complex and involves significant judgement, as these transactions often feature multiple elements that will have a material impact on the presentation and disclosure of these transactions in the financial statements and on key performance measures, including in particular classification of liabilities as finance debt. 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 complex 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.

As at 31 December 2019, the group's total financial assets and liabilities measured at fair value were \$12.5 billion and \$8.8 billion, of which level 3 derivative financial assets were \$5.3 billion and level 3 derivative financial liabilities were \$4.4 billion.

How the Critical Audit Matter was addressed in the Audit

Accounting for SCTs

For structured commodity transactions, we performed audit procedures to:

- Test controls related to the accounting for complex transactions.
- Develop an understanding of the commercial rationale of the transactions through review of transaction support documents and executed agreements, and discussions with management.
- Perform a detailed accounting analysis for a sample of structured commodity transactions involving significant day one profits, deferred working capital arrangements, offtake arrangements and/or commitments.

To assess the appropriateness of the accounting treatment of SCTs, we embedded technical accounting specialists within the audit team.

During the year we identified two new SCTs which were subjected to our audit procedures listed above. We also reconsidered the SCTs which were identified during 2018 and which have been subject to ongoing assessment in 2019.

Other level 3 financial instruments:

To address the complexities associated with auditing the value of level 3 financial instruments, the engagement 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 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 date, including:
 - Engaging a Deloitte valuations specialist to develop fair value estimates, using independently sourced inputs where these were available, and challenge 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. In situations where we utilised management’s inputs, these were compared to external data sources to ensure they were reasonable;
 - Evaluating management’s valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period; and
 - Comparing management’s input assumptions against the expected assumptions of other market participants and observable market data.

/s/ Deloitte LLP

London
United Kingdom
18 March 2020

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 2019, 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 2019, 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 2019, of the Company and our report dated 18 March 2020, expressed an unqualified opinion on those financial statements.

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

18 March 2020

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. (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 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 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 audit. 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 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/ 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 2019 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		\$ million		
	Note	2019	2018	2017
Sales and other operating revenues	5	278,397	298,756	240,208
Earnings from joint ventures – after interest and tax	16	576	897	1,177
Earnings from associates – after interest and tax	17	2,681	2,856	1,330
Interest and other income	7	769	773	657
Gains on sale of businesses and fixed assets	4	193	456	1,210
Total revenues and other income		282,616	303,738	244,582
Purchases	19	209,672	229,878	179,716
Production and manufacturing expenses		21,815	23,005	24,229
Production and similar taxes	5	1,547	1,536	1,775
Depreciation, depletion and amortization	5	17,780	15,457	15,584
Impairment and losses on sale of businesses and fixed assets	4	8,075	860	1,216
Exploration expense	8	964	1,445	2,080
Distribution and administration expenses		11,057	12,179	10,508
Profit before interest and taxation		11,706	19,378	9,474
Finance costs	7	3,489	2,528	2,074
Net finance expense relating to pensions and other post-retirement benefits	24	63	127	220
Profit before taxation		8,154	16,723	7,180
Taxation	9	3,964	7,145	3,712
Profit for the year		4,190	9,578	3,468
Attributable to				
BP shareholders		4,026	9,383	3,389
Non-controlling interests		164	195	79
		4,190	9,578	3,468
Earnings per share				
Profit for the year attributable to BP shareholders				
Per ordinary share (cents)				
Basic	11	19.84	46.98	17.20
Diluted	11	19.73	46.67	17.10
Per ADS (dollars)				
Basic	11	1.19	2.82	1.03
Diluted	11	1.18	2.80	1.03

Group statement of comprehensive income^a

For the year ended 31 December		\$ million		
	Note	2019	2018	2017
Profit for the year		4,190	9,578	3,468
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		1,538	(3,771)	1,986
Exchange (gains) losses on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		880	—	(120)
Available-for-sale investments		—	—	14
Cash flow hedges marked to market	30	(100)	(126)	197
Cash flow hedges reclassified to the income statement	30	106	120	116
Cash flow hedges reclassified to the balance sheet	30	—	—	112
Costs of hedging marked to market	30	(4)	(244)	—
Costs of hedging reclassified to the income statement	30	57	58	—
Share of items relating to equity-accounted entities, net of tax	16, 17	82	417	564
Income tax relating to items that may be reclassified	9	(70)	4	(196)
		2,489	(3,542)	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	24	328	2,317	3,646
Cash flow hedges that will subsequently be transferred to the balance sheet	30	(3)	(37)	—
Income tax relating to items that will not be reclassified	9	(157)	(718)	(1,303)
		168	1,562	2,343
Other comprehensive income		2,657	(1,980)	5,016
Total comprehensive income		6,847	7,598	8,484
Attributable to				
BP shareholders		6,674	7,444	8,353
Non-controlling interests		173	154	131
		6,847	7,598	8,484

^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 2018	46,352	(15,767)	(8,902)	(987)	78,748	99,444	2,104	101,548
Adjustment on adoption of IFRS 16, net of tax	—	—	—	—	(329)	(329)	(1)	(330)
At 1 January 2019	46,352	(15,767)	(8,902)	(987)	78,419	99,115	2,103	101,218
Profit for the year	—	—	—	—	4,026	4,026	164	4,190
Other comprehensive income	—	—	2,407	52	189	2,648	9	2,657
Total comprehensive income	—	—	2,407	52	4,215	6,674	173	6,847
Dividends ^b	—	—	—	—	(6,929)	(6,929)	(213)	(7,142)
Cash flow hedges transferred to the balance sheet, net of tax	—	—	—	23	—	23	—	23
Repurchase of ordinary share capital	—	—	—	—	(1,511)	(1,511)	—	(1,511)
Share-based payments, net of tax	173	1,355	—	—	(809)	719	—	719
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	5	5	—	5
Transactions involving non-controlling interests, net of tax	—	—	—	—	316	316	233	549
At 31 December 2019	46,525	(14,412)	(6,495)	(912)	73,706	98,412	2,296	100,708
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 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 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)
Repurchases 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

^a See Note 32 for further information.

^b See Note 10 for further information.

Group balance sheet

At 31 December		\$ million	
	Note	2019	2018*
Non-current assets			
Property, plant and equipment	12	132,642	135,261
Goodwill	14	11,868	12,204
Intangible assets	15	15,539	17,284
Investments in joint ventures	16	9,991	8,647
Investments in associates	17	20,334	17,673
Other investments	18	1,276	1,341
Fixed assets		191,650	192,410
Loans		630	637
Trade and other receivables	20	2,147	1,834
Derivative financial instruments	30	6,314	5,145
Prepayments		781	1,179
Deferred tax assets	9	4,560	3,706
Defined benefit pension plan surpluses	24	7,053	5,955
		213,135	210,866
Current assets			
Loans		339	326
Inventories	19	20,880	17,988
Trade and other receivables	20	24,442	24,478
Derivative financial instruments	30	4,153	3,846
Prepayments		857	963
Current tax receivable		1,282	1,019
Other investments	18	169	222
Cash and cash equivalents	25	22,472	22,468
		74,594	71,310
Assets classified as held for sale	2	7,465	—
		82,059	71,310
Total assets		295,194	282,176
Current liabilities			
Trade and other payables	22	46,829	46,265
Derivative financial instruments	30	3,261	3,308
Accruals		5,066	4,626
Lease liabilities	28	2,067	44
Finance debt ^a	26	10,487	9,329
Current tax payable		2,039	2,101
Provisions	23	2,453	2,564
		72,202	68,237
Liabilities directly associated with assets classified as held for sale	2	1,393	—
		73,595	68,237
Non-current liabilities			
Other payables	22	12,626	13,830
Derivative financial instruments	30	5,537	5,625
Accruals		996	575
Lease liabilities	28	7,655	623
Finance debt ^a	26	57,237	55,803
Deferred tax liabilities	9	9,750	9,812
Provisions	23	18,498	17,732
Defined benefit pension plan and other post-retirement benefit plan deficits	24	8,592	8,391
		120,891	112,391
Total liabilities		194,486	180,628
Net assets		100,708	101,548
Equity			
BP shareholders' equity	32	98,412	99,444
Non-controlling interests	32	2,296	2,104
Total equity	32	100,708	101,548

* Finance debt on the comparative balance sheet has been re-presented to align with the current period. See Note 1 for further information.

Helge Lund Chairman
 B Looney Chief executive officer
 18 March 2020

Group cash flow statement

For the year ended 31 December

		\$ million		
	Note	2019	2018	2017
Operating activities				
Profit before taxation		8,154	16,723	7,180
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	8	631	1,085	1,603
Depreciation, depletion and amortization	5	17,780	15,457	15,584
Impairment and (gain) loss on sale of businesses and fixed assets	4	7,882	404	6
Earnings from joint ventures and associates		(3,257)	(3,753)	(2,507)
Dividends received from joint ventures and associates		1,962	1,535	1,253
Interest receivable		(441)	(468)	(304)
Interest received		416	348	375
Finance costs	7	3,489	2,528	2,074
Interest paid		(2,870)	(1,928)	(1,572)
Net finance expense relating to pensions and other post-retirement benefits	24	63	127	220
Share-based payments		730	690	661
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	24	(238)	(386)	(394)
Net charge for provisions, less payments		(176)	986	2,106
(Increase) decrease in inventories		(3,406)	672	(848)
(Increase) decrease in other current and non-current assets		(2,335)	(2,858)	(4,848)
Increase (decrease) in other current and non-current liabilities		2,823	(2,577)	2,344
Income taxes paid		(5,437)	(5,712)	(4,002)
Net cash provided by operating activities		25,770	22,873	18,931
Investing activities				
Expenditure on property, plant and equipment, intangible and other assets		(15,418)	(16,707)	(16,562)
Acquisitions, net of cash acquired	3	(3,562)	(6,986)	(327)
Investment in joint ventures		(137)	(382)	(50)
Investment in associates		(304)	(1,013)	(901)
Total cash capital expenditure		(19,421)	(25,088)	(17,840)
Proceeds from disposals of fixed assets	4	500	940	2,936
Proceeds from disposals of businesses, net of cash disposed	4	1,701	1,911	478
Proceeds from loan repayments		246	666	349
Net cash used in investing activities		(16,974)	(21,571)	(14,077)
Financing activities^a				
Repurchase of shares		(1,511)	(355)	(343)
Lease liability payments		(2,372)	(35)	(45)
Proceeds from long-term financing		8,597	9,038	8,712
Repayments of long-term financing		(7,118)	(7,175)	(6,231)
Net increase (decrease) in short-term debt		180	1,317	(158)
Net increase (decrease) in non-controlling interests		566	—	1,063
Dividends paid				
BP shareholders	10	(6,946)	(6,699)	(6,153)
Non-controlling interests		(213)	(170)	(141)
Net cash provided by (used in) financing activities		(8,817)	(4,079)	(3,296)
Currency translation differences relating to cash and cash equivalents		25	(330)	544
Increase (decrease) in cash and cash equivalents		4	(3,107)	2,102
Cash and cash equivalents at beginning of year		22,468	25,575	23,484
Cash and cash equivalents at end of year		22,472	22,468	25,586

^a The presentation of financing cash flows for the comparative periods have been amended to align with the current period. 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 2019 were approved and signed by the chief executive officer and chairman on 18 March 2020 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 2019. 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; exploration and appraisal intangible assets; the recoverability of asset carrying values, including the estimation of reserves; 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 does not consider income taxes to represent a significant estimate or judgement for 2019, 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. The amount recognized for any non-controlling interest is measured at the present ownership's proportionate share in the recognized amounts of the acquiree's identifiable net assets. 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.

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

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.

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 2019. 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, as at 31 December 2019, Bob Dudley, has been a member of the board of directors of Rosneft since 2013 and remains one of BP's nominated directors following his resignation as BP's group chief executive. He is also 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 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.

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

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.

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 internal approval for development and recognition of proved reserves of oil and natural gas, 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. Upon internal approval for development and recognition of proved reserves, 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.

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

Significant judgement: exploration and appraisal intangible assets

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. The costs are carried based on the current regulatory and political environment or any known changes to that environment. 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.

In scenarios where the expected time horizon for establishing the development plan is lengthy or uncertain, greater judgement is required. BP is in the exploration and appraisal phase in certain Canadian oil sands assets that require further advancement of low-carbon extraction technology in order to achieve optimum development. Sufficient technological progress is expected to be achieved and therefore BP continues to carry the capitalized costs on its balance sheet.

The judgement disclosed in prior years in relation to expiring leases in the Gulf of Mexico is no longer considered to be significant following recent agreement of lease extensions with the US Bureau of Safety and Environmental Enforcement.

The carrying amount of capitalized costs is included in Note 8.

Property, plant and equipment

Property, plant and equipment owned by the group 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.

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 certain 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. Therefore, the charges are not dependent on management forecasts of future oil and gas prices. 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. Management does not believe that a reasonably possible change in the economic environment would result in a material change to the depreciation and amortization charge for other classes of assets.

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 232, which is unaudited. Details on BP's proved reserves and production compliance and governance processes are provided on page 286. The 2019 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 232.

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.

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

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. If it is probable that the value of the CGU will be primarily recovered through a disposal transaction, the expected disposal proceeds are considered in determining the recoverable amount. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

The business segment plans, which are approved on an annual basis by senior management, are the primary source of information for the determination of value in use. They contain forecasts for oil and natural gas production, refinery throughputs, sales volumes for various types of refined products (e.g. gasoline and lubricants), revenues, costs and capital expenditure. As an initial step in the preparation of these plans, various assumptions regarding market conditions, such as oil prices, natural gas prices, refining margins, refined product margins and cost inflation rates are set by senior management. These assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group 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. In limited circumstances where recent market transactions are not available for reference, discounted cash flow techniques are applied. 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.

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.

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

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, individual oil and gas properties may form separate CGUs whilst 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.

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 2019 relating to discount rates and oil and gas properties 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 CGU. 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 and incorporating a market participant capital structure. 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 2019 the post-tax discount rate was 6% (2018 6%) and the pre-tax discount rate typically ranged from 7% to 13% (2018 9%) depending on the applicable tax rate in the geographic location of the CGU. Where the CGU is located in a country that is judged to be higher risk an additional premium of 1% to 4% was added to the discount rates (2018 2%). The judgement of classifying a country as higher risk and the applicable premium 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 recoverable amount of oil and gas properties is primarily sensitive to changes in the oil and gas price assumptions. Further sensitivity analysis may be performed if a specific oil and gas property is identified to have low headroom above its carrying amount. In 2019, the group identified oil and gas properties with carrying amounts totalling \$25,092 million (2018 \$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 \$1,256 million (2018 \$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.

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

Oil and natural gas prices

The long-term price assumptions used for investment appraisal are recommended by the group chief economist after considering a range of external price, and supply and demand forecasts under various energy transition scenarios. They are reviewed and approved by management. As a result of the current uncertainty over the pace of transition to lower-carbon supply and demand and the social, political and environmental actions that will be taken to meet the goals of the Paris climate change agreement, the forecasts and scenarios considered include those where those goals are met as well as those where they are not met. The assumptions below represent management's best estimate of future prices; they do not reflect a specific scenario and sit within the range of the external forecasts considered.

The long-term price assumptions used to determine recoverable amount based on value-in-use impairments tests are derived from the central case investment appraisal assumptions (see page 19) of \$70 per barrel for Brent and \$4 per mmBtu for Henry Hub gas, both in 2015 prices (2018 \$75 per barrel and \$4 per mmBtu respectively, in 2015 prices). These long-term prices are applied from 2025 and 2032 respectively (2018 both from 2024) and continue to be inflated for the remaining life of the asset.

The price assumptions used over the periods to 2025 and 2032 have been set such that there is a linear progression from our best estimate of 2020 prices, which were set by reference to 2019 average prices, to the long-term assumptions.

The majority of BP's reserves and resources that support the carrying value of the group's oil and gas properties are expected to be produced over the next 10 years. Average prices (in real 2015 terms) used to estimate cash flows over this period are \$67 per barrel for Brent and \$3.1 per mmBtu for Henry Hub gas.

Oil prices fell 10% in 2019 from 2018 due to trade tensions, a macroeconomic downturn, and a slight slowdown in oil demand. OPEC+ production restraint, unplanned outages, and sanctions on Venezuela and Iran kept prices from falling further. BP's long-term assumption for oil prices is higher than the 2019 price average, based on the judgement that current price levels would not encourage sufficient investment to meet global oil demand sustainably in the longer term, especially given the financial requirements of key low-cost oil producing economies.

US gas prices dropped by around 15% in 2019 compared to 2018. After an initial spike in January, they remained relatively low for much of the year due to a combination of strong associated gas production growth, and storage levels coming back to normal. US gas demand growth was much lower than the exceptional increase in 2018, while LNG exports continued to expand. BP's long-term price assumption for US gas is higher than recent market prices due to forecast rising domestic demand, rapidly increasing pipeline and LNG exports, and lowest cost resources being absorbed leading to production of more expensive gas, as well as requiring increased investment in infrastructure.

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

Management tested the impact of a reduction in prices of 15% against the best estimate for Brent oil and Henry Hub gas in all future years. These price reductions in isolation could indicatively lead to a reduction in the carrying amount of BP's oil and gas properties in the range of \$2-3 billion, which is approximately 1-2% of the net book value of property, plant and equipment as at 31 December 2019.

Management also tested the impact of a scenario where Brent oil and Henry Hub gas prices start 15% lower than the best estimate and gradually reduce to 25% lower than the best estimate by 2040. Although this is not considered to be a reasonably possible change in the long-term assumptions within the next financial year, it reflects the inherent uncertainty in forecasting long-term prices. These price reductions in isolation could indicatively lead to a reduction in the carrying amount of BP's oil and gas properties in the range of \$4-5 billion which is approximately 3-4% of the net book value of property, plant and equipment as at 31 December 2019. Additionally, such a price reduction does not indicate a reduction in the carrying amount of the Upstream goodwill balance.

These sensitivity analyses do not, however, represent management's best estimate of any impairments that might be recognized as they do not fully incorporate consequential changes that may arise, such as reductions in costs and changes to business plans, phasing of development, levels of reserves and resources, and production volumes. As the extent of a price reduction increases, the more likely it is that costs would decrease across the industry. The above sensitivity analyses therefore do not reflect a linear relationship between price and value that can be extrapolated. Past experience of performing impairment tests suggests that any impairment arising from such price reductions is likely to be lower once all these factors are taken into consideration. The interdependency of these inputs and risk factors plus the diverse characteristics 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 the price assumptions.

The decline in oil and natural gas prices in the first quarter of 2020 is not expected to materially impact the recoverable amount of the group's oil and natural gas properties.

Oil and natural gas reserves

In addition to oil and natural 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 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.

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 \$11.9 billion on its balance sheet (2018 \$12.2 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. Sensitivities and additional information 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 that convey the right to control the use of an identified asset for a period of time in exchange for consideration are accounted for as leases. The right to control is conveyed if BP has both the right to obtain substantially all of the economic benefits from, and the right to direct the use of, the identified asset throughout the period of use. An asset is identified if it is explicitly or implicitly specified by the agreement and any substitution rights held by the lessor over the asset are not considered substantive.

Agreements that convey the right to control the use of an intangible asset including rights to explore for or use hydrocarbons are not accounted for as leases. See significant accounting policy: intangible assets.

A lease liability is recognized on the balance sheet on the lease commencement date at the present value of future lease payments over the lease term. The discount rate applied is the rate implicit in the lease if readily determinable, otherwise an incremental borrowing rate is used. The incremental borrowing rate is determined based on factors such as the group's cost of borrowing, lessee legal entity credit risk, currency and lease term. The lease term is the non-cancellable period of a lease together with any periods covered by an extension option that BP is reasonably certain to exercise, or periods covered by a termination option that BP is reasonably certain not to exercise. The future lease payments included in the present value calculation are any fixed payments, payments that vary depending on an index or rate, payments due for the reasonably certain exercise of options and expected residual value guarantee payments.

Payments that vary based on factors other than an index or a rate such as usage, sales volumes or revenues are not included in the present value calculation and are recognized in the income statement. The lease liability is recognized on an amortized cost basis with interest expense recognized in the income statement over the lease term, except for where capitalized as exploration, appraisal or development expenditure.

The right-of-use asset is recognized on the balance sheet as property, plant and equipment at a value equivalent to the initial measurement of the lease liability adjusted for lease prepayments, lease incentives, initial direct costs and any restoration obligations. The right-of-use asset is depreciated typically on a straight-line basis over the lease term. The depreciation charge is recognized in the income statement except for where capitalized as exploration, appraisal or development expenditure. Right-of-use assets are assessed for impairment in line with the accounting policy for impairment of property, plant and equipment, intangible assets, and goodwill.

Agreements may include both lease and non-lease components. Payments for lease and non-lease components are allocated on a relative stand-alone selling price basis except for leases of retail service stations where the group has elected not to separate non-lease payments from the calculation of the lease liability and right-of-use asset.

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

If the lease term at commencement of the agreement is less than 12 months, a lease liability and right-of-use asset are not recognized, and a lease expense is recognized in the income statement on a straight-line basis.

If a significant event or change in circumstances, within the control of BP, arises that affects the reasonably certain lease term or there are changes to the lease payments, the present value of the lease liability is remeasured using the revised term and payments, with the right-of-use asset adjusted by an equivalent amount.

Modifications to a lease agreement beyond the original terms and conditions are accounted for as a re-measurement of the lease liability with a corresponding adjustment to the right-of-use asset. Any gain or loss on modification is recognized in the income statement. Modifications that increase the scope of the lease at a price commensurate with the stand-alone selling price are accounted for as a separate new lease.

The group recognizes the full lease liability, rather than its working interest share, for leases entered into on behalf of a joint operation if the group has the primary responsibility for making the lease payments. In such cases, BP's working interest share of the right-of-use asset is recognized if it is jointly controlled by the group and the other joint operators, and a receivable is recognized for the share of the asset transferred to the other joint operators. If BP is a non-operator, a payable to the operator is recognized if they have the primary responsibility for making the lease payments and BP has joint control over the right-of-use asset, otherwise no balances are recognized.

As noted in 'Impact of new International Financial Reporting Standards - IFRS 16 'Leases'', BP elected to apply the 'modified retrospective' transition approach on adoption of IFRS 16. Under this approach, comparative periods' financial information is not restated. The accounting policy applicable for leases in the comparative periods only is disclosed in the following paragraphs.

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 rights to receive cash flows have been transferred to a third party along with either substantially all of the risks and rewards or control of the asset. This includes the derecognition of receivables for which discounting arrangements are entered into.

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.

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. The group does not have any investments for which this election has been made.

Derivatives designated as hedging instruments in an effective hedge

Derivatives designated as hedging instruments in an effective hedge 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, in the case of certain money market funds, fair value through profit or loss.

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

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. As lifetime expected credit losses are recognized for trade receivables and the tenor of substantially all of other in-scope financial assets is less than 12 months there is no significant difference between the measurement of 12-month and lifetime expected credit losses for the group. 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

Derivatives designated as hedging instruments in an effective hedge 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.

The group's trade payables include some supplier arrangements that utilize letter of credit facilities (see Note 29 - Liquidity risk for further information). The group assesses the payables subject to these arrangements to determine whether they should continue to be classified as trade payables and give rise to operating cash flows or finance debt and financing cash flows. The criteria used in making this assessment include the payment terms for the amount due relative to terms commonly seen in the markets in which BP operates. Liabilities subject to these arrangements with payment terms of up to approximately 60 days are generally considered to be trade payables and give rise to operating cash flows.

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.

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:

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

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 or sales and other operating revenues as appropriate.

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

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 foreign currency basis spread are recognized in other comprehensive income to the extent that they relate to the hedged item. For time-period related hedged items, the amount recognized in other comprehensive income is amortized to profit or loss on a straight line basis 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 estimate and judgement: 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 primarily 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 (including volatility and correlation) and modelled using the maximum available external information. Additionally, where limited data exists for certain products, prices are determined using historical and long-term pricing relationships. The use of alternative assumptions or valuation methodologies may result in significantly different values for these derivatives. A reasonably possible change in the price assumptions used in the models relating to index price would not have a material impact on net assets and the Group income statement primarily as a result of offsetting movements between derivative assets and liabilities. For more information, including the carrying amounts of level 3 derivatives, 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, rather than as a derivative.

Offsetting of financial assets and liabilities

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

Provisions 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 2.5% (2018 3.0%).

Provisions are split between amounts expected to be settled within 12 months of the balance sheet date (current) and amounts expected to be settled later (non-current).

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

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

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 or utilisation of 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.

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. The group has assessed that no material decommissioning provisions should be recognized as at 31 December 2019 (2018 no material provisions) for assets sold to third parties where the sale transferred the decommissioning obligation to the new owner.

Decommissioning provisions associated with downstream refineries 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 refineries 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 2019 was a nominal rate of 2.5% (2018 a nominal rate of 3.0%), which was based on long-dated US government bonds. The weighted average period over which decommissioning and environmental costs are generally expected to be incurred is estimated to be approximately 18 years (2018 18 years) and 6 years (2018 6 years) respectively.

Further information about the group's provisions is provided in Note 23. 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 \$1.4 billion (2018 \$1.3 billion) on the value of the group's provisions.

A two-year change in the timing of expected future decommissioning expenditures does not have a material impact on the value of the group's decommissioning provision. Management do not consider a change of greater than two years to be reasonably possible either in the next financial year or as a result of changes in the longer-term economic environment.

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.

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

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.

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.

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

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 within the carrying amount of the applicable tax asset or liability 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.

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 2019 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. 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. The cost of treasury shares subsequently sold or reissued is calculated on a weighted-average basis. 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.

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

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. 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.

Certain contracts entered into by the group that result in physical delivery of products such as crude oil, natural gas and refined products are required by IFRS 9 to be accounted for as derivative financial instruments. The group's counterparties in these transactions may, however, meet the IFRS 15 definition of a customer. Revenue recognized relating to such contracts when physical delivery occurs is, therefore, measured at the contractual transaction price and presented together with revenue from contracts with customers. Changes in the fair value of derivative assets and liabilities prior to physical delivery are excluded from revenue from contracts with customers and are classified as other operating revenues. See also Impact of new International Financial Reporting Standards- Not yet adopted- *IFRIC agenda decision on IFRS 9 'Financial instruments'* below.

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.

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.

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.

Contract asset and contract liability balances are included within amounts presented for trade receivables and other payables respectively.

Finance costs

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

Impact of new International Financial Reporting Standards

BP adopted IFRS 16 'Leases', which replaced IAS 17 'Leases' and IFRIC 4 'Determining whether an arrangement contains a lease', with effect from 1 January 2019. 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 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 is recognized in profit or loss over the lease term.

BP 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. Comparative information in the group balance sheet and group cash flow statement has, however, been re-presented to align with current year presentation, showing lease liabilities and lease liability payments as separate line items. These were previously included within finance debt and repayments of long-term financing line items respectively. Amounts presented in these line items for the comparative periods relate to leases accounted for as finance leases under IAS 17. We do not consider any of the judgements or estimates made on transition to IFRS 16 to be significant.

IFRS 16 introduces a revised definition of a lease. As permitted by the standard, BP elected not to reassess the existing population of leases under the new definition and only applies the new definition for the assessment of contracts entered into after the transition date. On transition the standard permitted, 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 a historical basis as if the standard had always applied. BP elected to use the historical asset measurement for its more material leases and used the asset equals liability approach for the remainder of the population. In measuring the right-of-use asset BP applied the transition practical expedient to exclude initial direct costs. BP also elected 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 performing impairment tests on transition.

The effect on the group's balance sheet is set out further below. The presentation and timing of recognition of charges in the income statement has changed following the adoption of IFRS 16. The operating lease expense previously reported under IAS 17, typically on a straight-line basis, has been replaced by depreciation of the right-of-use asset and interest on the lease liability. In the cash flow statement payments are now presented as financing cash flows, representing repayments of principal, 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. In prior years, operating lease payments were principally presented within cash flows from operating activities.

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

The following table provides a reconciliation of the operating lease commitments as at 31 December 2018 to the total lease liability 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 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 lease liabilities at 1 January 2019	9,900

Leases not yet commenced: The operating lease commitments disclosed as at 31 December 2018 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. Commitments for leases not yet commenced as at 31 December 2019 are disclosed in note 28.

Short-term leases and leases below materiality threshold: As part of the transition to IFRS 16, BP elected not to recognize assets and liabilities relating to short-term leases i.e. leases with a term of less than 12 months and 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 include amounts related to such leases.

Effect of discounting: The amount of the lease liability recognized in accordance with IFRS 16 is on a discounted basis whereas the operating lease commitments information as at 31 December 2018 is presented on an undiscounted basis. The discount rates used on transition were 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 used on transition was around 3.5%, with a weighted average remaining lease term of around nine 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.

Impact on leases in joint operations: The operating lease commitments for leases within joint operations as at 31 December 2018 were included on the basis of BP's net working interest, 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 were 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 as at 31 December 2018 was based on the variable factor as at inception of the lease and was not updated to reflect subsequent changes in the variable factor. Such subsequent changes in the lease payments were treated as contingent rentals and charged to profit or loss as and when paid. Under IFRS 16 the lease liability is adjusted whenever the lease payments are changed in response to changes in the variable factor, and for transition the liability was 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 were redetermined with the benefit of hindsight, on the basis that BP was reasonably certain to exercise its option to terminate those leases before the full term.

Under IAS 17 finance leases were recognized on the group balance sheet and 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 previous finance leases within joint operations are on a net or gross basis as appropriate as described above.

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

In addition to the lease liability, other line items on the group balance sheet adjusted on transition to IFRS 16 include property, plant and equipment for the right-of-use assets, lease related prepayments, receivables from joint operation partners, accruals, payables to operators of joint operations, onerous lease 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)
Lease liabilities	44	2,196	2,152
Finance debt	9,329	9,329	—
Provisions	2,564	2,547	(17)
Non-current liabilities			
Other payables	13,830	14,013	183
Accruals	575	548	(27)
Lease liabilities	623	7,704	7,081
Finance debt	55,803	55,803	—
Deferred tax liabilities	9,812	9,767	(45)
Provisions	17,732	17,657	(75)
Net assets^a	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)

^a Net assets also includes the line items not affected by the transition to IFRS 16 that are not presented separately in the table

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

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

Not yet adopted

The following pronouncements from the IASB have not been adopted by the group in these financial statements as they will only become effective for future financial reporting periods. In addition, the group is voluntarily changing certain accounting policies from 1 January 2020 following an IFRIC agenda decision on IFRS 9 'Financial instruments'. There are no other standards, amendments or 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 17 'Insurance Contracts'

IFRS 17 'Insurance Contracts' provides a new general model for accounting for contracts where the issuer accepts significant insurance risk from another party and agrees to compensate that party if a future uncertain event adversely affects them. IFRS 17 replaces IFRS 4 'Insurance Contracts' and will be effective for BP for the financial reporting period commencing 1 January 2022 subject to endorsement by the UK and the EU. BP has commenced an assessment of the impact of IFRS 17 but it is not expected to have a significant effect on future financial reporting.

Interest Rate Benchmark Reform: Amendments to IFRS 9 'Financial instruments'

Amendments to IFRS 9 were issued in September 2019 to provide temporary relief from applying specific hedge accounting requirements to hedging relationships directly affected by interest rate benchmark reforms. The reliefs have the effect that the uncertainty over the interest rate benchmark reforms should not generally result in discontinuation of hedge accounting. The amendments have been endorsed by the EU. BP will adopt the IFRS 9 amendments in the financial reporting period commencing 1 January 2020.

The reliefs provided by the amendments would allow BP to assume that:

- the interest rate benchmark component at initial designation of fair value hedges is separately identifiable; and
- the interest rate benchmark is not altered for the purposes of assessing the economic relationship between the hedged item and the hedging instrument for fair value hedges.

The amendments are applicable to all of the group's fair value hedges disclosed in note 30.

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

IFRIC agenda decision on IFRS 9

In March 2019, the IFRIC issued an agenda decision on the application of IFRS 9 to the physical settlement of contracts to buy or sell a non-financial item such as commodities that are not accounted for as 'own-use' contracts. The IFRIC concluded that such contracts are settled by the delivery or receipt of a non-financial item in exchange for both cash and the settlement of the derivative asset or liability. BP regularly enters into forward sale and purchase contracts. As described in the group's accounting policy for revenue, revenue recognized at the time such contracts are physically settled is measured at the contractual transaction price and is presented together with revenue from contracts with customers in these financial statements. From 1 January 2020, however, the group has changed its accounting policy for these contracts in accordance with the conclusions included in the agenda decision. Purchases and revenues from such contracts will be measured at the contractual transaction price plus the carrying amount of the related derivative at the date of settlement. Furthermore, revenues on such sales contracts will no longer be presented together with the group's revenue from contracts with customers but will be included in other revenues. This change will have a significant effect on the group's disclosures in relation to revenue from contracts with customers. For 2019, it is currently estimated that the amount of revenue measured at the contractual transaction price presented together with revenue from contracts with customers in these financial statements that would be presented as other revenues following application of this change in accounting policy is approximately \$130 billion. Comparative information for revenue from contracts with customers (see Note 6) will be restated in BP's 2020 financial statements.

Gains and losses on these realized physically settled derivative contracts will also be included in other revenues. The group expects there to be no material effect on reported profit as presented in the group income statement or on net assets as a result of these changes.

2. Non-current assets held for sale

The carrying amount of assets classified as held for sale at 31 December 2019 is \$7,465 million, with associated liabilities of \$1,393 million. These principally relate to two material disposal transactions which have been classified as held for sale in the group balance sheet.

On 27 August 2019, BP announced that it had agreed to sell all its Alaska operations and interests to Hilcorp Energy for up to \$5.6 billion, subject to customary closing adjustments, of which \$1.6 billion is contingent on future cash flows. The sale will include BP's entire upstream and midstream business in the state, including BP Exploration (Alaska) Inc., which owns all of BP's upstream oil and gas interests in Alaska, and BP Pipelines (Alaska) Inc.'s 49% interest in the Trans Alaska Pipeline System (TAPS). BP will retain decommissioning liability relating to TAPS, which will be partially offset by a 30% cost reimbursement from Hilcorp. The deal, which is subject to governmental authorizations, is expected to complete during 2020. Assets of \$6,518 million and associated liabilities of \$969 million relating to this transaction are classified as held for sale at 31 December 2019.

In November 2019, BP agreed to sell its interests in the San Juan basin in Colorado and New Mexico to IKAV. The deal is expected to complete during the first half of 2020. Assets and associated liabilities relating to this transaction are classified as held for sale at 31 December 2019.

The total assets and liabilities held for sale, which are all in the Upstream segment, are set out in the table below.

	\$ million
	2019
Property, plant and equipment	6,359
Intangible assets	610
Investments in associates	43
Inventories	318
Trade and other receivables	135
Assets classified as held for sale	7,465
Trade and other payables	(33)
Lease liabilities	(280)
Provisions	(1,012)
Defined benefit pension plan and other post-retirement benefit plan deficits	(68)
Liabilities directly associated with assets classified as held for sale	(1,393)

3. Business combinations and other significant transactions

Business combinations

As agreed as part of the original transaction, \$3,480 million was paid in 2019 in respect of the 2018 acquisition of Petrohawk Energy Corporation from BHP Billiton that is described below. Payments on this transaction are now complete. A number of other individually insignificant business combinations were also undertaken by BP in 2019.

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, was \$10,302 million, which was all paid in cash.

The transaction was accounted for as a business combination using the acquisition method. The fair values of the identifiable assets and liabilities acquired, as at the date of acquisition, are shown in the table below. No goodwill was recognized on the acquisition and no significant adjustments were made to the provisional fair values of the identifiable assets and liabilities acquired when those values were finalized.

	\$ 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

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 for 2018. Goodwill of \$804 million, resulting from the recognition of a deferred tax liability as part of the transaction accounting, was 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		
	2019	2018	2017
Gains on sale of businesses and fixed assets			
Upstream	143	437	526
Downstream	50	15	674
Other businesses and corporate	—	4	10
	193	456	1,210
Losses on sale of businesses and fixed assets			
Upstream	415	707	127
Downstream	57	59	88
Other businesses and corporate	887	11	—
	1,359	777	215
Impairment losses			
Upstream	6,752	400	1,138
Downstream	65	12	69
Other businesses and corporate	30	254	32
	6,847	666	1,239
Impairment reversals			
Upstream	(131)	(580)	(176)
Downstream	—	(2)	(62)
Other businesses and corporate	—	(1)	—
	(131)	(583)	(238)
Impairment and losses on sale of businesses and fixed assets	8,075	860	1,216

Disposals

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

	\$ million		
	2019	2018	2017
Proceeds from disposals of fixed assets	500	940	2,936
Proceeds from disposals of businesses, net of cash disposed	1,701	1,911	478
	2,201	2,851	3,414
By business			
Upstream	2,048	2,145	1,183
Downstream	152	120	2,078
Other businesses and corporate	1	586	153
	2,201	2,851	3,414

At 31 December 2019, deferred consideration relating to disposals amounted to \$159 million receivable within one year (2018 \$35 million and 2017 \$259 million) and \$125 million receivable after one year (2018 \$304 million and 2017 \$268 million). In addition, contingent consideration receivable relating to disposals amounted to \$598 million at 31 December 2019 (2018 \$893 million and 2017 \$237 million). These amounts of contingent consideration are reported within Other investments on the group balance sheet - see Note 18 for further information.

Upstream

In 2019, losses included \$191 million fair value movements in relation to contingent consideration arising from the prior period disposal of the Bruce, Keith and Devenick assets and \$171 million in relation to severance costs associated with the divestment of our Alaskan business.

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.

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.

4. Disposals and impairment – continued

Other businesses and corporate

In 2019 losses on disposal of businesses and fixed assets were principally in respect of the reclassification of accumulated foreign exchange losses from reserves to the income statement upon the contribution of our Brazilian biofuels business to a new 50:50 joint venture BP Bunge Bioenergia.

In 2018 proceeds from disposals were principally in respect of life insurance policies in the US and wind farms within our US wind business. Summarized financial information relating to the sale of businesses is shown in the table below.

The principal transaction categorized as a business disposal in 2019 was the sale of our interests in the Gulf of Suez oil concessions in Egypt.

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.

	\$ million		
	2019	2018	2017
Non-current assets	1,653	3,274	735
Current assets	507	173	57
Non-current liabilities	(257)	(250)	(173)
Current liabilities	(108)	(97)	(86)
Total carrying amount of net assets disposed	1,795	3,100	533
Recycling of foreign exchange on disposal	880	—	—
Costs on disposal	190	3	3
	2,865	3,103	536
Gains (losses) on sale of businesses	(1,190)	(221)	44
Total consideration	1,675	2,882	580
Non-cash consideration	(938)	(282)	(216)
Consideration received (receivable) ^a	964	(689)	114
Proceeds from the sale of businesses, net of cash disposed ^b	1,701	1,911	478

^a \$633 million relates to deposits received in advance of the disposal of our Alaska business and certain assets in our BPX business

^b Proceeds are stated net of cash and cash equivalents disposed of \$30 million (2018 \$15 million and 2017 \$25 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, and Note 15 for further information on impairments by asset category.

Upstream

Impairment losses and reversals in all years relate primarily to producing and midstream assets.

The 2019 impairment losses of \$6,752 million related to various assets, with the most significant charges arising in the US. Impairment losses arose primarily as a result of the decision to dispose of certain assets, including \$4,703 million in relation to completed and expected disposals in BPX Energy and \$1,264 million relating to the expected disposal of our Alaskan business; of these amounts \$355 million primarily relates to impairment of associated goodwill.

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.

Downstream

Impairment losses totalling \$65 million, \$12 million, and \$69 million were recognized in 2019, 2018 and 2017 respectively.

Other businesses and corporate

Impairment losses totalling \$30 million, \$254 million, and \$32 million were recognized in 2019, 2018 and 2017 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 2019, 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.

In February 2020, BP announced plans for a future reorganization of the group's operating segments. The group's current segmental reporting structure is expected to remain in place throughout 2020 with any changes coming into effect from 1 January 2021.

^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					
	2019					
By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
Segment revenues						
Sales and other operating revenues	54,501	250,897	—	1,788	(28,789)	278,397
Less: sales and other operating revenues between segments	(27,034)	(973)	—	(782)	28,789	—
Third party sales and other operating revenues	27,467	249,924	—	1,006	—	278,397
Earnings from joint ventures and associates – after interest and tax	603	374	2,295	(15)	—	3,257
Segment results						
Replacement cost profit (loss) before interest and taxation	4,917	6,502	2,316	(2,771)	75	11,039
Inventory holding gains (losses) ^a	(8)	685	(10)	—	—	667
Profit (loss) before interest and taxation	4,909	7,187	2,306	(2,771)	75	11,706
Finance costs						(3,489)
Net finance expense relating to pensions and other post-retirement benefits						(63)
Profit before taxation						8,154
Other income statement items						
Depreciation, depletion and amortization						
US	4,672	1,335	—	55	—	6,062
Non-US	9,560	1,586	—	572	—	11,718
Charges for provisions, net of write-back of unused provisions, including change in discount rate	118	507	—	560	—	1,185
Segment assets						
Investments in joint ventures and associates	12,196	3,609	12,927	1,593	—	30,325
Additions to non-current assets ^b	16,254	4,014	—	2,345	—	22,613

^a See explanation of inventory holding gains and losses on page 177.

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

	\$ 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 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,c}	24,266	3,609	—	477	—	28,352

^a See explanation of inventory holding gains and losses on page 177.

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

^c Amounts have been restated to include acquisitions

5. Segmental analysis – continued

						\$ 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 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

^a See explanation of inventory holding gains and losses on page 177.

	\$ million		
	2019		
By geographical area	US	Non-US	Total
Revenues			
Third party sales and other operating revenues ^a	89,334	189,063	278,397
Other income statement items			
Production and similar taxes	315	1,232	1,547
Non-current assets			
Non-current assets ^{b c}	57,757	133,398	191,155

^a Non-US region includes UK \$63,194 million

^b Non-US region includes UK \$22,881 million

^c Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

	\$ million		
	2018		
By geographical area	US	Non-US	Total
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
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.

5. Segmental analysis – continued

	\$ million		
	2017		
By geographical area	US	Non-US	Total
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

^a Non-US region includes UK \$48,837 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		
	2019	2018	2017
Crude oil	62,130	65,276	49,670
Oil products	180,528	195,466	159,821
Natural gas, LNG and NGLs	20,167	21,745	16,196
Non-oil products and other revenues from contracts with customers	13,254	13,768	12,538
Revenues from contracts with customers	276,079	296,255	238,225

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.

See Note 1 - impact of new International Financial Reporting Standards- Not yet adopted- IFRIC agenda decision on IFRS 9 'Financial instruments' for further information on changes to the presentation of revenue from contracts with customers that will apply from 1 January 2020.

7. Income statement analysis

	\$ million		
	2019	2018	2017
Interest and other income			
Interest income from			
Financial assets measured at amortized cost	371	421	288
Financial assets measured at fair value through profit or loss	49	39	—
Other income	349	313	369
	769	773	657
Currency exchange losses charged to the income statement ^a	37	368	83
Expenditure on research and development	364	429	391
Costs relating to the Gulf of Mexico oil spill (pre-interest and tax) ^b	319	714	2,687
Finance costs			
Interest payable on lease liabilities ^c	379	51	56
Interest payable on other liabilities measured at amortized cost	2,410	2,147	1,662
Capitalized at 3.50% (2018 3.56% and 2017 2.25%) ^d	(374)	(419)	(297)
Unwinding of discount on provisions ^e	505	210	150
Unwinding of discount on other payables measured at amortized cost	569	539	503
	3,489	2,528	2,074

^a Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.

^b Included within production and manufacturing expenses.

^c Interest payable on lease liabilities in comparative periods relate to leases previously classified as finance leases under IAS 17.

^d Tax relief on capitalized interest is approximately \$51 million (2018 \$55 million and 2017 \$64 million).

^e From 1 July 2018, the group changed its method of discounting and unwinding provisions from using real rates to using nominal rates.

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		
	2019	2018	2017
Exploration and evaluation costs			
Exploration expenditure written off ^a	631	1,085	1,603
Other exploration costs	333	360	477
Exploration expense for the year	964	1,445	2,080
Impairment losses	2	137	—
Intangible assets – exploration and appraisal expenditure ^b	14,091	15,989	17,026
Liabilities	73	60	82
Net assets	14,018	15,929	16,944
Cash used in operating activities	333	360	477
Cash used in investing activities	1,215	1,119	1,901

^a 2018 includes \$447 million in the deepwater Gulf of Mexico principally relating to licence expiries. 2017 included write-offs 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. For further information see Upstream – Exploration on page 53.

^b 2019 includes approximately \$2.5 billion relating to Canadian oil sands. See Note 1 for further information.

The carrying amount, by location, of exploration and appraisal expenditure capitalized as intangible assets at 31 December 2019 is shown in the table below.

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

9. Taxation

Tax on profit

	\$ million		
	2019	2018	2017
Current tax			
Charge for the year	5,316	6,217	4,208
Adjustment in respect of prior years ^a	(68)	(221)	58
	5,248	5,996	4,266
Deferred tax ^b			
Origination and reversal of temporary differences in the current year	(1,190)	907	(503)
Adjustment in respect of prior years	(94)	242	(51)
	(1,284)	1,149	(554)
Tax charge on profit	3,964	7,145	3,712

^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 2019, the total tax charge recognized within other comprehensive income was \$227 million (2018 \$714 million charge and 2017 \$1,499 million charge), 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 \$37 million (2018 \$17 million charge and 2017 \$263 million charge).

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 before taxation.

9. Taxation – continued

	\$ million		
	2019	2018	2017
Profit before taxation	8,154	16,723	7,180
Tax charge on profit	3,964	7,145	3,712
Effective tax rate	49%	43%	52%
Tax rate computed at the weighted average statutory rate ^a	52	43	44
Increase (decrease) resulting from			
Tax reported in equity-accounted entities	(7)	(5)	(7)
Deferred tax not recognized ^b	(2)	1	6
Tax incentives for investment	(3)	(2)	(6)
Foreign exchange	1	3	(4)
Items not deductible for tax purposes	4	1	5
Impact of US tax reform ^c	—	(1)	12
Other ^b	4	3	2
Effective tax rate	49	43	52

^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 A minor amendment has been made to 2017 and 2018 to align with current period presentation.

^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.

Deferred tax

	\$ million	
	2019	2018
Analysis of movements during the year in the net deferred tax liability		
At 31 December	6,106	3,513
Adjustment on adoption of IFRS 9 ^a	—	(36)
Adjustment on adoption of IFRS 16 ^b	(75)	—
At 1 January	6,031	3,477
Exchange adjustments	72	(68)
Charge (credit) for the year in the income statement	(1,284)	1,149
Charge for the year in other comprehensive income	233	734
Charge for the year in equity	37	17
Acquisitions, disposals and other additions ^c	101	797
At 31 December	5,190	6,106

^a 2018 reflects the deferred tax impact of adjustments recorded by the group on adoption of IFRS 9. See BP Annual Report and Form 20-F 2018- Financial statements- Note 1 for further information.

^b 2019 reflects the deferred tax impact of adjustments recorded by the group on adoption of IFRS 16. See Note 1 for further information.

^c 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:

	Income statement ^{ab}			Balance sheet ^{ab}	
	2019	2018	2017	2019	2018
					\$ million
Deferred tax liability					
Depreciation	(1,436)	(1,297)	(3,971)	22,627	22,565
Pension plan surpluses	(31)	65	(12)	2,290	1,956
Derivative financial instruments	29	(36)	(27)	29	—
Other taxable temporary differences	159	(57)	(64)	1,496	1,224
	(1,279)	(1,325)	(4,074)	26,442	25,745
Deferred tax asset					
Lease liabilities	264	8	(16)	(1,380)	(90)
Pension plan and other post-retirement benefit plan deficits	62	(6)	340	(1,367)	(1,319)
Decommissioning, environmental and other provisions	(472)	1,505	3,503	(7,579)	(7,126)
Derivative financial instruments	63	(31)	(47)	(24)	(95)
Tax credits	(336)	123	1,476	(3,964)	(3,626)
Loss carry forward	12	559	(964)	(5,834)	(5,900)
Other deductible temporary differences	402	316	(772)	(1,104)	(1,483)
	(5)	2,474	3,520	(21,252)	(19,639)
Net deferred tax charge (credit) and net deferred tax liability ^c	(1,284)	1,149	(554)	5,190	6,106
Of which – deferred tax liabilities				9,750	9,812
– deferred tax assets				4,560	3,706

^a The 2017 and 2018 income statement and 2018 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 2019 balance sheet is impacted by the adoption of IFRS 16 and minor amendments have been made to the balance sheet and income statement comparatives to align with current period presentation.

^c Included within the net deferred tax liability is a deferred tax asset balance of \$5,526 million (2018 \$5,562 million) related to the Gulf of Mexico oil spill.

Of the \$4,560 million of deferred tax assets recognised on the group balance sheet at 31 December 2019 (2018 \$3,706 million), \$2,421 million (2018 \$2,758 million) relates to entities that have suffered a loss in either the current or preceding period. This amount is supported by forecasts that indicate sufficient future taxable profits will be available to utilize such assets. For 2019, \$2,421 million relates to the US (2018 \$1,563 million relates to the US and \$1,108 million relates to India).

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.

At 31 December	\$ billion	
	2019	2018
Unused US state tax losses ^a	2.3	6.6
Unused tax losses – other jurisdictions ^b	3.5	4.3
Unused tax credits	25.4	22.5
of which – arising in the UK ^c	21.5	18.7
– arising in the US ^d	3.9	3.8
Deductible temporary differences ^e	40.4	37.3
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	1.5	1.5

^a For 2019 these losses expire in the period 2020-2039 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 2019 the US unused tax credits expire in the period 2020-2029.

^e The majority comprises fixed asset temporary differences in the UK. Substantially all of the temporary differences have no expiry date.

Impact of previously unrecognized deferred tax or write-down of deferred tax assets on tax charge	\$ million		
	2019	2018	2017
Current tax benefit relating to the utilization of previously unrecognized deferred tax assets	272	83	22
Deferred tax benefit arising from the reversal of a previous write-down of deferred tax assets	96	—	—
Deferred tax benefit relating to the recognition of previously unrecognized deferred tax assets	364	112	436
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	73	169	78

10. Dividends

The quarterly dividend which is expected to be paid on 27 March 2020 in respect of the fourth quarter 2019 is 10.50 cents per ordinary share (\$0.630 per American Depositary Share (ADS)). The corresponding amount in sterling was announced on 16 March 2020.

	Pence per share			Cents per share			\$ million	
	2019	2018	2017	2019	2018	2017	2018	2017
Dividends announced and paid in cash								
Preference shares							1	1
Ordinary shares								
March	7.7380	7.1691	8.1587	10.25	10.00	10.00	1,435	1,828
June	8.0660	7.4435	7.7563	10.25	10.00	10.00	1,779	1,727
September	8.3480	7.9296	7.6213	10.25	10.25	10.00	1,656	1,409
December	7.8250	8.0251	7.4435	10.25	10.25	10.00	2,075	1,734
	31.9770	30.5673	30.9798	41.00	40.50	40.00	6,946	6,699
Dividend announced, paid in March 2020				10.50			2,120	

The details of the scrip dividends issued are shown in the table below. The board decided not to offer a scrip dividend alternative in respect of the third quarter 2019 dividend paid in December 2019 and fourth quarter 2019 dividend expected to be paid on 27 March 2020.

	2019	2018	2017
Number of shares issued (thousand)	208,927	195,305	289,789
Value of shares issued (\$ million)	1,387	1,381	1,714

The financial statements for the year ended 31 December 2019 do not reflect the dividend announced on 4 February 2020 and paid in March 2020; this will be treated as an appropriation of profit in the year ending 31 December 2020.

11. Earnings per share

Per ordinary share	Cents per share		
	2019	2018	2017
Basic earnings per share	19.84	46.98	17.20
Diluted earnings per share	19.73	46.67	17.10

Per American Depositary Share (ADS)	Dollars per share		
	2019	2018	2017
Basic earnings per share	1.19	2.82	1.03
Diluted earnings per share	1.18	2.80	1.03

Basic earnings per ordinary share amounts are calculated by dividing the profit for the year attributable to BP ordinary shareholders by the weighted average number of ordinary shares outstanding during the year.

The weighted 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		
	2019	2018	2017
Profit attributable to BP shareholders	4,026	9,383	3,389
Less: dividend requirements on preference shares	1	1	1
Profit for the year attributable to BP ordinary shareholders	4,025	9,382	3,388

	Shares thousand		
	2019	2018	2017
Basic weighted average number of ordinary shares	20,284,859	19,970,215	19,692,613
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	114,811	132,278	123,829
Weighted average number of ordinary shares outstanding used to calculate diluted earnings per share	20,399,670	20,102,493	19,816,442

	Shares thousand		
	2019	2018	2017
Basic weighted average number of ordinary shares – ADS equivalent	3,380,809	3,328,369	3,282,102
Potential dilutive effect of ordinary shares (ADS equivalent) issuable under employee share-based payment plans	19,136	22,046	20,638
Weighted average number of ordinary shares (ADS equivalent) outstanding used to calculate diluted earnings per share	3,399,945	3,350,415	3,302,740

11. Earnings per share – continued

The number of ordinary shares outstanding at 31 December 2019, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 20,241,170,965. Between 31 December 2019 and 27 February 2020, the latest practicable date before the completion of these financial statements, there was a net decrease of 46,527,851 in the number of ordinary shares outstanding primarily as a result of share issues in relation to employee share-based payment plans. A further 120 million of shares have also been repurchased in January 2020 as part of the share buyback programme at a total cost of \$776 million.

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 100-127.

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	2019		2018	
	Number of options ^{ab} thousand	Weighted average exercise price \$	Number of options ^{ab} thousand	Weighted average exercise price \$
Outstanding	17,112	4.91	19,437	4.28
Exercisable	1,067	3.97	481	4.69
Dilutive effect	3,990	n/a	6,123	n/a

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

^b At 31 December 2019 the quoted market price of one BP ordinary share was £4.72 (2018 £4.96).

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	2019		2018	
	Number of shares ^a thousand			
Vesting				
Within one year	91,105	108,934		
1 to 2 years	89,939	106,337		
2 to 3 years	80,844	71,407		
3 to 4 years	725	588		
Over 4 years	576	799		
	263,189	288,065		
Dilutive effect	92,343	127,165		

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

There has been a net decrease of 37,497,364 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2019 and 27 February 2020.

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- owned property, plant and equipment (PP&E)								
At 1 January 2019	3,562	1,502	232,684	45,721	2,747	10,183	8,866	305,265
Exchange adjustments	(22)	5	—	(158)	15	(3)	(69)	(232)
Additions	88	93	13,237	2,433	172	274	644	16,941
Acquisitions	51	—	—	—	—	—	8	59
Transfers from intangible assets	—	—	1,885	—	—	—	—	1,885
Reclassified as assets held for sale	(26)	—	(22,602)	—	(76)	(6,708)	—	(29,412)
Deletions	(44)	(178)	(10,852)	(1,272)	(326)	(272)	(755)	(13,699)
At 31 December 2019	3,609	1,422	214,352	46,724	2,532	3,474	8,694	280,807
Depreciation- owned PP&E								
At 1 January 2019	626	697	133,687	20,512	2,041	7,819	5,146	170,528
Exchange adjustments	(4)	5	—	(63)	12	(3)	(45)	(98)
Charge for the year	44	59	13,012	1,705	168	173	420	15,581
Impairment losses	1	1	5,871	64	1	404	4	6,346
Impairment reversals	—	—	(129)	—	—	(2)	—	(131)
Reclassified as assets held for sale	—	—	(17,764)	—	(69)	(5,478)	—	(23,311)
Deletions	(86)	(65)	(9,911)	(691)	(147)	(169)	(660)	(11,729)
At 31 December 2019	581	697	124,766	21,527	2,006	2,744	4,865	157,186
Owned PP&E- net book amount at 31 December 2019								
	3,028	725	89,586	25,197	526	730	3,829	123,621
Right-of-use assets- net book amount at 31 December 2019 ^c								
	—	1,196	128	1,241	16	3,385	3,055	9,021
Total PP&E- net book amount at 31 December 2019								
	3,028	1,921	89,714	26,438	542	4,115	6,884	132,642
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 ^b	—	—	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
Assets held under finance leases at net book amount included above ^d								
At 31 December 2018	—	2	12	207	—	295	6	522
Assets under construction included above								
At 31 December 2019								23,897
At 31 December 2018								22,522
Depreciation charge for the year on right-of-use assets								
2019		220	31	671	9	784	526	2,241

^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.

^c \$653 million of drilling rig right-of-use assets and \$2,929 million of shipping vessel right-of-use assets are included in Plant, machinery and equipment and Transportation respectively.

^d Leases previously classified as finance leases are included within right-of-use assets following the implementation of IFRS 16 'Leases'; see Note 1 for further information. The reconciliation of owned property, plant and equipment for 2019 does not include right-of-use assets and, therefore, the cost and depreciation at 1 January 2019 is not equal to the cost and depreciation of total property, plant and equipment at 31 December 2018. The relevant amounts excluded are cost of \$1,083 million and depreciation of \$559 million relating to leases previously classified as finance leases.

13. Capital commitments

Authorized future capital expenditure for property, plant and equipment (excluding right-of-use assets) by group companies for which contracts had been signed at 31 December 2019 amounted to \$11,382 million (2018 \$8,319 million, 2017 \$11,340 million). BP has contracted capital commitments amounting to \$787 million (2018 \$1,227 million, 2017 \$1,451 million) in relation to associates. BP's share of contracted capital commitments of joint ventures amounted to \$1,024 million (2018 \$619 million, 2017 \$483 million).

14. Goodwill and impairment review of goodwill

	\$ million	
	2019	2018
Cost		
At 1 January	12,815	12,163
Exchange adjustments	79	(210)
Acquisitions and other additions ^a	26	1,046
Deletions	(55)	(184)
At 31 December	12,865	12,815
Impairment losses		
At 1 January	611	612
Exchange adjustments	—	—
Impairment losses for the year	386	—
Deletions	—	(1)
At 31 December	997	611
Net book amount at 31 December	11,868	12,204
Net book amount at 1 January	12,204	11,551

^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

	2019	2018
Goodwill at 31 December		
Upstream	7,958	8,346
Downstream	3,904	3,802
Other businesses and corporate	6	56
	11,868	12,204

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

	2019	2018
Goodwill	7,958	8,346
Excess of recoverable amount over carrying amount	93,250	53,391

The table above shows the carrying amount of goodwill for the segment and the excess of the recoverable amount, based on a pre-tax value-in-use calculation, over the carrying amount (headroom) at the date of the test. The increase in headroom principally arises from acquisitions (including the acquisition from BHP), new activity and discount rate changes, net of highly probable and completed divestments and price assumption changes.

Goodwill impairments of \$386 million, related to goodwill allocated to expected divestments, were recognized during 2019 (2018 nil).

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.

14. Goodwill and impairment review of goodwill – continued

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 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. Due to economic developments, regulatory change and emissions reduction activity arising from climate concern and other factors, future commodity prices and other assumptions 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 fully reflect the specific impacts for each contractual arrangement and will not capture all favourable impacts that may arise from cost deflation. A detailed calculation at any given price or production profile may, therefore, produce a different result.

It is estimated that no reasonable sustained fall in the oil or gas price assumption over the next 20 years would individually 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 829 mmbob per year (2018 829 mmbob per year). It is estimated that no reasonably possible change in production volumes 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 reasonably possible change in the pre-tax discount rate would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the segment. The weighted average discount rate used in the test is 12%.

Downstream

	\$ million					
	2019			2018		
	Lubricants	Other	Total	Lubricants	Other	Total
Goodwill	2,779	1,125	3,904	2,692	1,110	3,802

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 2018 was used as the basis for the tests in 2019 as the criteria of IAS 36 were considered satisfied: the headroom was substantial in 2018; 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.

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.

15. Intangible assets

	\$ million					
	2019			2018		
	Exploration and appraisal expenditure ^a	Other intangibles	Total	Exploration and appraisal expenditure ^a	Other intangibles	Total
Cost						
At 1 January	17,053	4,504	21,557	17,886	4,488	22,374
Exchange adjustments	—	2	2	—	(128)	(128)
Acquisitions	—	35	35	—	25	25
Additions	1,268	457	1,725	1,095	318	1,413
Transfers to property, plant and equipment	(1,885)	—	(1,885)	(901)	—	(901)
Reclassified as assets held for sale	(671)	—	(671)	—	—	—
Deletions	(459)	(98)	(557)	(1,027)	(199)	(1,226)
At 31 December	15,306	4,900	20,206	17,053	4,504	21,557
Amortization						
At 1 January	1,064	3,209	4,273	860	3,159	4,019
Exchange adjustments	—	4	4	—	(77)	(77)
Charge for the year	631	331	962	1,085	326	1,411
Impairment losses	2	2	4	137	—	137
Reclassified as assets held for sale	(61)	—	(61)	—	—	—
Deletions	(421)	(94)	(515)	(1,018)	(199)	(1,217)
At 31 December	1,215	3,452	4,667	1,064	3,209	4,273
Net book amount at 31 December	14,091	1,448	15,539	15,989	1,295	17,284
Net book amount at 1 January	15,989	1,295	17,284	17,026	1,329	18,355

^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. In December 2019, BP and Bunge both contributed their Brazilian biofuels and biopower businesses into a new joint venture, BP Bunge Bioenergia. BP owns 50% of the new entity.

	\$ million		
	2019	2018	2017
Sales and other operating revenues	14,139	13,258	11,380
Profit before interest and taxation	975	1,396	1,394
Finance costs	111	85	100
Profit before taxation	864	1,311	1,294
Taxation	288	414	117
Profit for the year	576	897	1,177
Other comprehensive income	(6)	6	8
Total comprehensive income	570	903	1,185
Non-current assets	13,408	10,399	
Current assets	3,738	2,935	
Total assets	17,146	13,334	
Current liabilities	2,514	1,715	
Non-current liabilities	4,676	3,017	
Total liabilities	7,190	4,732	
Net assets	9,956	8,602	
Group investment in joint ventures			
Group share of net assets (as above)	9,956	8,602	
Loans made by group companies to joint ventures	35	45	
	9,991	8,647	

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

	\$ million					
	2019		2018		2017	
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	4,884	431	4,603	251	3,578	352

	\$ million					
	2019		2018		2017	
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	1,812	225	1,336	300	1,257	176

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	
	2019	2018	2017	2019	2018
Rosneft	2,295	2,283	922	12,927	10,074
Other associates	386	573	408	7,407	7,599
	2,681	2,856	1,330	20,334	17,673

The associate that is material to the group at both 31 December 2019 and 2018 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 Rosneftgaz, owned 50.0% plus one share of the voting shares of Rosneft at 31 December 2019.

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 2019 compared with 31 December 2018 principally relates to earnings from Rosneft and foreign exchange effects, which have been recognized in other comprehensive income, offset by dividends.

17. Investments in associates – continued

The value of BP's 19.75% shareholding in Rosneft based on the quoted market share price of \$7.21 per share (2018 \$6.18 per share) was \$15,090 million at 31 December 2019 (2018 \$12,934 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 2019, 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		
	2019	2018	2017
Sales and other operating revenues	134,046	131,322	103,028
Profit before interest and taxation	17,473	18,886	9,949
Finance costs	1,281	2,785	2,228
Profit before taxation	16,192	16,101	7,721
Taxation	3,058	2,957	1,742
Non-controlling interests	1,514	1,585	1,311
Profit for the year	11,620	11,559	4,668
Other comprehensive income	572	2,086	2,810
Total comprehensive income	12,192	13,645	7,478
Non-current assets	161,327	137,038	
Current assets	38,657	43,438	
Total assets	199,984	180,476	
Current liabilities	44,459	41,311	
Non-current liabilities	79,327	78,754	
Total liabilities	123,786	120,065	
Net assets	76,198	60,411	
Less: non-controlling interests	10,744	9,403	
	65,454	51,008	

The group received dividends, net of withholding tax, of \$785 million from Rosneft in 2019 (2018 \$620 million and 2017 \$314 million).

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

	\$ million								
	BP share								
	2019			2018			2017		
	Rosneft ^a	Other	Total	Rosneft ^a	Other	Total	Rosneft ^a	Other	Total
Sales and other operating revenues	26,474	7,934	34,408	25,936	9,134	35,070	20,348	7,600	27,948
Profit before interest and taxation	3,451	788	4,239	3,730	1,150	4,880	1,965	626	2,591
Finance costs	253	87	340	550	78	628	440	54	494
Profit before taxation	3,198	701	3,899	3,180	1,072	4,252	1,525	572	2,097
Taxation	604	315	919	584	499	1,083	344	164	508
Non-controlling interests	299	—	299	313	—	313	259	—	259
Profit for the year	2,295	386	2,681	2,283	573	2,856	922	408	1,330
Other comprehensive income	113	(25)	88	412	(1)	411	555	1	556
Total comprehensive income	2,408	361	2,769	2,695	572	3,267	1,477	409	1,886
Non-current assets	31,862	11,504	43,366	27,065	10,787	37,852			
Current assets	7,635	1,924	9,559	8,579	2,398	10,977			
Total assets	39,497	13,428	52,925	35,644	13,185	48,829			
Current liabilities	8,781	1,908	10,689	8,159	2,232	10,391			
Non-current liabilities	15,667	4,577	20,244	15,554	3,817	19,371			
Total liabilities	24,448	6,485	30,933	23,713	6,049	29,762			
Net assets	15,049	6,943	21,992	11,931	7,136	19,067			
Less: non-controlling interests	2,122	—	2,122	1,857	—	1,857			
	12,927	6,943	19,870	10,074	7,136	17,210			
Group investment in associates									
Group share of net assets (as above)	12,927	6,943	19,870	10,074	7,136	17,210			
Loans made by group companies to associates	—	464	464	—	463	463			
	12,927	7,407	20,334	10,074	7,599	17,673			

^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.

Sales to associates	2019		2018		\$ million	
	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	1,544	243	2,064	393	1,612	216

Purchases from associates	2019		2018		\$ million	
	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	9,503	1,641	14,112	2,069	11,613	1,681

In addition to the transactions shown in the table above, in 2018 BP acquired a 49% stake in LLC Kharampurneftegaz, a Rosneft subsidiary, which develops resources within the Kharampurskoe and Festivalnoye licence areas in Yamalo-Nenets 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 purchases from associates relate to crude oil and oil products transactions with Rosneft. Sales to associates are related to various entities.

BP has commitments amounting to \$11,198 million (2018 \$11,303 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

	2019		2018		\$ million	
	Current	Non-current	Current	Non-current	Current	Non-current
Equity investments ^a	—	571	1	482		
Other	169	705	221	859		
	169	1,276	222	1,341		

^a The majority of equity investments are unlisted.

Other investments includes \$598 million relating to contingent consideration amounts arising on disposals (2018 \$893 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

	2019		2018		\$ million	
Crude oil	5,610		4,878			
Natural gas	222		322			
Refined petroleum and petrochemical products	12,907		10,419			
	18,739		15,619			
Trading inventories	182		282			
	18,921		15,901			
Supplies	1,959		2,087			
	20,880		17,988			
Cost of inventories expensed in the income statement	209,672		229,878			

The inventory valuation at 31 December 2019 is stated net of a provision of \$650 million (2018 \$1,009 million) to write down inventories to their net realizable value, of which \$290 million (2018 \$604 million) relates to hydrocarbon inventories. The net credit to the income statement in the year in respect of inventory net realizable value provisions was \$348 million (2018 \$552 million charge), of which \$309 million credit (2018 \$553 million charge) 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			
	2019		2018	
	Current	Non-current	Current	Non-current
Financial assets				
Trade receivables	19,424	22	19,414	7
Amounts receivable from joint ventures and associates	672	2	642	2
Other receivables	3,325	826	3,275	740
	23,421	850	23,331	749
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset	201	—	214	—
Sales taxes and production taxes	640	538	790	482
Other receivables	180	759	143	603
	1,021	1,297	1,147	1,085
	24,442	2,147	24,478	1,834

In both 2019 and 2018 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					
	2019		2018		2017	
	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	416	235	335	314	392	335
Adjustment on adoption of IFRS 9	—	—	115	(85)	—	—
At 1 January – IFRS 9	416	235	450	229	392	335
Charged to costs and expenses	206	28	30	10	68	47
Charged to other accounts ^a	(2)	—	(12)	(1)	13	3
Deductions	(111)	(14)	(52)	(3)	(138)	(71)
At 31 December	509	249	416	235	335	314

^a Principally exchange adjustments.

Valuation and qualifying accounts relating to trade and other receivables comprise expected credit loss allowances in 2019 and 2018 and impairment provisions recognized on an incurred loss basis in 2017. The adjustment on adoption of IFRS 9 relates to the additional loss allowance required by IFRS 9's expected credit loss model. The expected credit loss allowance comprises \$414 million (2018 \$327 million) relating to receivables that were credit-impaired at the end of the year and \$95 million (2018 \$89 million) relating to receivables that were not credit-impaired at the end of the year. 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 2019.

Valuation and qualifying accounts relating to fixed asset investments comprise impairment provisions for investments in equity-accounted entities in 2019 and 2018. This includes expected credit loss allowances of \$2 million (2018 \$44 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 (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.

22. Trade and other payables

	2019		\$ million	
	Current	Non-current	Current	Non-current
Financial liabilities				
Trade payables	30,538	—	26,252	—
Amounts payable to joint ventures and associates	1,866	—	2,369	—
Payables for capital expenditure and acquisitions ^a	3,868	1,196	7,325	1,345
Payables related to the Gulf of Mexico oil spill	1,617	10,863	2,279	11,922
Other payables	5,810	133	4,980	318
	43,699	12,192	43,205	13,585
Non-financial liabilities				
Sales taxes, customs duties, production taxes and social security	2,381	33	2,272	35
Other payables	749	401	788	210
	3,130	434	3,060	245
	46,829	12,626	46,265	13,830

^a 2018 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.

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.

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.

Payables related to the Gulf of Mexico oil spill 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 \$5,166 million payable over 13 years, \$2,742 million payable over 14 years and \$3,782 million payable over 13 years respectively at 31 December 2019. Reported within net cash provided by operating activities in the group cash flow statement is a net cash outflow of \$2,694 million (2018 outflow of \$3,531 million, 2017 outflow of \$5,336 million) related to the Gulf of Mexico oil spill, which includes payments made in relation to these agreements. For 2018 and 2017 payments under the 2012 agreement with the US government to resolve all federal criminal claims arising from the incident are also included. For full details of these agreements, see *BP Annual Report and Form 20-F 2015*.

Payables related to the Gulf of Mexico oil spill at 31 December 2019 also include amounts payable for settled economic loss and property damage claims which are payable over a period of up to eight years.

23. Provisions

	\$ million				
	Decommissioning	Environmental	Litigation and claims	Other	Total
At 1 January 2019 ^a	13,613	1,567	1,718	3,306	20,204
Exchange adjustments	74	(1)	—	(19)	54
Acquisitions	13	—	47	22	82
Increase (decrease) in existing provisions	1,045	272	290	960	2,567
Write-back of unused provisions	(22)	(43)	(15)	(361)	(441)
Unwinding of discount	415	45	28	17	505
Change in discount rate	1,360	40	31	11	1,442
Utilization	(9)	(252)	(674)	(665)	(1,600)
Reclassified to other payables	(187)	—	(139)	(328)	(654)
Reclassified as liabilities directly associated with assets held for sale	(1,004)	(8)	—	—	(1,012)
Deletions	(188)	—	(5)	(3)	(196)
At 31 December 2019	15,110	1,620	1,281	2,940	20,951
Of which – current	317	280	558	1,298	2,453
– non-current	14,793	1,340	723	1,642	18,498
Of which – Gulf of Mexico oil spill	—	—	189	—	189

^a Includes adjustment of \$92 million for the implementation of IFRS 16. See Note 1 for further information.

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 2019 are provisions for deferred employee compensation of \$311 million (2018 \$338 million).

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

23. Provisions – continued

Gulf of Mexico oil spill

The group has recognized certain assets, payables and provisions and incurs certain residual costs relating to the Gulf of Mexico oil spill that occurred in 2010. In addition to the Litigation and claims narrative provided in this note, for further information see Notes 7, 9, 20, 22, 29, 33 and Legal proceedings on pages 319-320.

Litigation and claims- PSC settlements

The Economic and Property Damages Settlement Agreement (EPD Settlement Agreement) with the Plaintiff's 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 319.

The litigation and claims provision reflects the latest estimate for the remaining costs associated with the PSC settlements. These costs relate predominantly to business economic loss (BEL) claims and associated administration costs. Only a very small number of claims remained to be determined by the end of 2019 however certain BEL claims determined by the DHCSSP have been and continue to be appealed by BP and/or the claimants. 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 settlements are expected to be made over the next couple 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.

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.

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. During 2019 the committee was composed of six BP employees appointed by the president of BP Corporation North America Inc. (the appointing officer). A seventh BP employee was added to the committee on 1 January 2020. 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 2019 the aggregate level of contributions was \$349 million (2018 \$610 million and 2017 \$637 million). The aggregate level of contributions in 2020 is expected to be approximately \$550 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 \$1,276 million at 31 December 2019, 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 302.

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 2019 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 2019.

24. Pensions and other post-retirement benefits – continued

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 2019. 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		%
	2019	2018	2017	2019	2018	2017	2019	2018	2017
Discount rate for plan liabilities	2.1	2.9	2.5	3.1	4.1	3.5	1.3	2.0	1.9
Rate of increase in salaries	3.4	3.8	4.1	3.9	3.9	4.1	3.1	3.1	3.0
Rate of increase for pensions in payment	2.7	3.0	2.9	—	—	—	1.5	1.5	1.4
Rate of increase in deferred pensions	2.7	3.0	2.9	—	—	—	0.5	0.5	0.6
Inflation for plan liabilities	2.7	3.1	3.1	1.5	1.5	1.7	1.7	1.7	1.6

Financial assumptions used to determine benefit expense	UK			US			Eurozone		%
	2019	2018	2017	2019	2018	2017	2019	2018	2017
Discount rate for plan service cost	3.0	2.6	2.7	4.2	3.6	4.1	2.5	2.4	2.1
Discount rate for plan other finance expense	2.9	2.5	2.7	4.1	3.5	3.9	2.0	1.9	1.7
Inflation for plan service cost	3.1	3.1	3.2	1.5	1.7	1.8	1.7	1.6	1.6

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.

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:

Mortality assumptions	UK			US			Eurozone		Years
	2019	2018	2017	2019	2018	2017	2019	2018	2017
Life expectancy at age 60 for a male currently aged 60	27.3	27.4	27.4	24.9	25.1	25.1	25.7	25.6	25.1
Life expectancy at age 60 for a male currently aged 40	28.9	28.9	29.0	26.7	26.9	26.8	28.3	28.1	27.6
Life expectancy at age 60 for a female currently aged 60	28.7	28.8	28.8	28.0	28.5	28.4	29.1	29.0	29.0
Life expectancy at age 60 for a female currently aged 40	30.5	30.6	30.5	29.7	30.1	30.0	31.2	31.2	31.4

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 2019, the UK and the US plans switched 2% and nil of plan assets respectively from equities to bonds (2018 12.5% and 10% respectively).

24. Pensions and other post-retirement benefits – continued

The current asset allocation policy for the major plans at 31 December 2019 was as follows:

Asset category	UK	US
	%	%
Total equity (including private equity)	28	40
Bonds/cash (including LDI)	65	60
Property/real estate	7	—

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2019 were \$4,804 million (2018 \$4,197 million) of government-issued nominal bonds and \$19,462 million (2018 \$17,491 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 197.

					\$ million
	UK ^a	US ^b	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2019					
Listed equities – developed markets	6,285	1,290	495	371	8,441
– emerging markets	1,096	124	61	64	1,345
Private equity ^c	2,675	1,474	—	3	4,152
Government issued nominal bonds ^d	4,884	2,100	959	572	8,515
Government issued index-linked bonds ^d	19,462	—	100	—	19,562
Corporate bonds ^d	6,132	2,304	569	256	9,261
Property ^e	2,507	—	96	27	2,630
Cash	426	289	33	93	841
Other	98	74	30	26	228
Debt (repurchase agreements) used to fund liability driven investments	(7,436)	—	—	—	(7,436)
	36,129	7,655	2,343	1,412	47,539
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

^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 transaction price or third-party net asset, revenue or earnings based valuations that generally result in the use of significant unobservable inputs.

^d Bonds held by pension plans are valued using quoted prices in active markets.

^e Properties are valued based on an analysis of recent market transactions supported by market knowledge derived from third-party professional valuers that generally result in the use of significant unobservable inputs.

24. Pensions and other post-retirement benefits – continued

	\$ million				
	2019				
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost ^a	227	263	81	38	609
Past service cost ^b	2	—	5	(1)	6
Settlement ^b	—	(13)	8	—	(5)
Operating charge relating to defined benefit plans	229	250	94	37	610
Payments to defined contribution plans	42	188	7	38	275
Total operating charge	271	438	101	75	885
Interest income on plan assets ^a	(909)	(285)	(43)	(46)	(1,283)
Interest on plan liabilities	757	387	133	69	1,346
Other finance (income) expense	(152)	102	90	23	63
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	2,945	1,079	220	97	4,341
Change in financial assumptions underlying the present value of the plan liabilities	(2,294)	(1,036)	(748)	(92)	(4,170)
Change in demographic assumptions underlying the present value of the plan liabilities	136	91	3	(4)	226
Experience gains and losses arising on the plan liabilities	(57)	(22)	6	4	(69)
Remeasurements recognized in other comprehensive income	730	112	(519)	5	328
Movements in benefit obligation during the year					
Benefit obligation at 1 January	26,830	9,696	6,906	1,686	45,118
Exchange adjustments	942	—	(142)	26	826
Operating charge relating to defined benefit plans	229	250	94	37	610
Interest cost	757	387	133	69	1,346
Contributions by plan participants ^c	20	—	2	6	28
Benefit payments (funded plans) ^d	(1,207)	(830)	(76)	(75)	(2,188)
Benefit payments (unfunded plans) ^d	(6)	(205)	(273)	(15)	(499)
Reclassified as assets held for sale	—	(146)	—	—	(146)
Disposals	—	—	(30)	—	(30)
Remeasurements	2,215	967	739	92	4,013
Benefit obligation at 31 December ^{a e}	29,780	10,119	7,353	1,826	49,078
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	32,085	7,195	2,112	1,290	42,682
Exchange adjustments	1,141	—	(43)	24	1,122
Interest income on plan assets ^{a f}	909	285	43	46	1,283
Contributions by plan participants ^c	20	—	2	6	28
Contributions by employers (funded plans)	236	4	85	24	349
Benefit payments (funded plans) ^d	(1,207)	(830)	(76)	(75)	(2,188)
Reclassified as assets held for sale	—	(78)	—	—	(78)
Remeasurements ^f	2,945	1,079	220	97	4,341
Fair value of plan assets at 31 December ^g	36,129	7,655	2,343	1,412	47,539
Surplus (deficit) at 31 December	6,349	(2,464)	(5,010)	(414)	(1,539)
Represented by					
Asset recognized	6,588	387	27	51	7,053
Liability recognized	(239)	(2,851)	(5,037)	(465)	(8,592)
	6,349	(2,464)	(5,010)	(414)	(1,539)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	6,588	387	(136)	(87)	6,752
Unfunded	(239)	(2,851)	(4,874)	(327)	(8,291)
	6,349	(2,464)	(5,010)	(414)	(1,539)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(29,541)	(7,268)	(2,479)	(1,499)	(40,787)
Unfunded	(239)	(2,851)	(4,874)	(327)	(8,291)
	(29,780)	(10,119)	(7,353)	(1,826)	(49,078)

^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 in the Eurozone have arisen from restructuring programmes and represent charges for special termination benefits reflecting the increased liability arising as a result of early retirements. Settlements in the US are the result of a buy-out transaction for the pensions of a group of low value annuitants.

^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 \$2,304 million benefits and \$346 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 \$7,789 million for pension liabilities and \$2,330 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes \$4,567 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 196.

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 196.

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	—	—	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

^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.

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 2019 for the group's pensions and other post-retirement benefit expense would have had the effects shown in the tables below. The effects shown for the expense in 2020 comprise the total of current service cost and net finance income or expense.

	\$ million					
	UK		US		One percentage point Eurozone	
	Increase	Decrease	Increase	Decrease	Increase	Decrease
Discount rate ^a						
Effect on expense in 2020	(274)	227	(66)	58	(1)	(11)
Effect on obligation at 31 December 2019	(4,729)	6,364	(1,191)	1,478	(1,060)	1,347
Inflation rate ^b						
Effect on expense in 2020	171	(134)	11	(9)	35	(27)
Effect on obligation at 31 December 2019	4,711	(3,890)	67	(54)	978	(824)
Salary growth						
Effect on expense in 2020	42	(36)	13	(11)	7	(7)
Effect on obligation at 31 December 2019	604	(525)	80	(67)	93	(89)

^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.

	\$ million		
	UK	US	Eurozone
Longevity			
Effect on expense in 2020		31	6
Effect on obligation at 31 December 2019	1,140	147	306

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 2029 and the weighted average duration of the defined benefit obligations at 31 December 2019 are as follows:

	\$ million				
	UK	US	Eurozone	Other	Total
Estimated future benefit payments					
2020	1,065	743	333	104	2,245
2021	1,078	789	323	98	2,288
2022	1,098	711	319	101	2,229
2023	1,138	718	314	98	2,268
2024	1,151	699	300	99	2,249
2025-2029	5,895	3,277	1,438	489	11,099
					Years
Weighted average duration	18.3	13.2	16.4	13.0	

25. Cash and cash equivalents

	\$ million	
	2019	2018
Cash	6,462	6,148
Term bank deposits	10,296	13,105
Cash equivalents (excluding term bank deposits)	5,714	3,215
	22,472	22,468

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 2019 includes \$1,676 million (2018 \$1,350 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 \$4,678 million (2018 \$4,693 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					
	2019			2018		
	Current	Non-current	Total	Current	Non-current	Total
Borrowings	10,487	57,237	67,724	9,329	55,803	65,132

As a result of the adoption of IFRS 16 'Leases', leases that were previously classified as finance leases under IAS 17 are now presented as 'Lease liabilities' on the group balance sheet and therefore do not form part of finance debt. Comparative information for finance debt has been amended to be on a consistent basis with amounts presented for 2019. See Note 1 and Note 27 for further information.

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 \$8,166 million (2018 \$7,175 million) and issued commercial paper of \$2,279 million (2018 \$2,040 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
	2019				
US dollar	4	5	25,634	3	41,871
Other currencies	6	10	183	7	36
			25,817		41,907
					2018
US dollar	4	4	17,264	4	47,461
Other currencies	5	5	323	8	84
			17,587		47,545
					65,132

Comparative information in the table above has been amended to exclude previously classified finance lease liabilities of \$667 million from US dollar and other currencies, primarily from fixed-rate debt. The calculation of the comparative weighted-average interest rate and time for which rate is fixed is unchanged for US dollar fixed-rate debt and was previously 7% and 18 years respectively for other currencies fixed-rate debt.

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 2019, 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 significant 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.

	\$ million			
	2019		2018	
	Fair value	Carrying amount	Fair value	Carrying amount
Short-term borrowings	2,321	2,321	2,153	2,153
Long-term borrowings	67,055	65,403	63,213	62,979
Total finance debt	69,376	67,724	65,366	65,132

27. Capital disclosures and 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 basis of gearing (previously termed 'net debt ratio'), that is, the ratio of net debt to net debt plus equity. Net debt is calculated as 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 gearing are non-GAAP measures. BP believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of finance debt, related hedges and cash and cash equivalents in total. Gearing 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 gearing within a 20-30% band and maintain a significant liquidity buffer. At 31 December 2019, gearing was 31.1% (2018 30.0%).

As a result of the adoption of IFRS 16 'Leases' from 1 January 2019, leases that were previously classified as finance leases under IAS 17 are now presented as 'Lease liabilities' on the group balance sheet and therefore do not form part of finance debt. Comparative information for finance debt (previously also termed 'gross debt'), net debt and gearing have been amended to be on a consistent basis with amounts presented for 2019. The relevant amount for finance lease liabilities that has been excluded from comparative information for 2018 is \$667 million. The previously disclosed amounts for finance debt and net debt for 2018 were \$65,799 million and \$44,144 million respectively. The previously disclosed gearing for 2018 was 30.3%.

At 31 December	\$ million	
	2019	2018
Finance debt	67,724	65,132
Less: fair value asset (liability) of hedges related to finance debt ^a	(190)	(813)
	67,914	65,945
Less: cash and cash equivalents	22,472	22,468
Net debt	45,442	43,477
Equity	100,708	101,548
Gearing	31.1%	30.0%

^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 \$601 million (2018 liability of \$827 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 out flow of \$286 million (2018 net cash flow \$nil) and fair value loss of \$60 million (2018 fair value losses of \$193 million).

Net debt including leases is shown in the table below.

At 31 December	\$ million	
	2019	2018
Net debt	45,442	43,477
Lease liabilities	9,722	667
Net partner (receivable) payable for leases entered into on behalf of joint operations	(158)	—
Net debt including leases	55,006	44,144

An analysis of changes in liabilities arising from financing activities is provided below.

	\$ million				
	Finance debt	Hedge-accounted derivatives	Lease liabilities	Net partner payable for leases entered into on behalf of joint operations	Total liabilities arising from financing activities
At 1 January 2019	65,132	813	667	—	66,612
Adjustment on adoption of IFRS 16 ^a	—	—	9,233	217	9,450
Exchange adjustments	(62)	—	(4)	8	(58)
Net financing cash flow	1,671	2	(2,372)	(14)	(713)
Fair value (gains) losses	924	(1,104)	—	—	(180)
New and remeasured leases/joint operation payables	—	—	2,614	82	2,696
Other movements	59	479	(416)	(3)	119
At 31 December 2019	67,724	190	9,722	290	77,926
At 1 January 2018	62,574	175	656	—	63,405
Exchange adjustments	(237)	—	(22)	—	(259)
Net financing cash flow	3,540	(360)	(35)	—	3,145
Fair value (gains) losses	(856)	998	—	—	142
New leases	—	—	74	—	74
Other movements	111	—	(6)	—	105
At 31 December 2018	65,132	813	667	—	66,612

^a See Note 1 for information on adoption of IFRS 16 'Leases'.

28. Leases

The group leases a number of assets as part of its activities. This primarily includes drilling rigs in the Upstream segment and retail service stations, oil depots and storage tanks in the Downstream segment as well as office accommodation and vessel charters across the group. The weighted-average remaining lease term for the total lease portfolio is around 9 years. Some leases will have payments that vary with market interest or inflation rates. Certain leases contain residual value guarantees, which may be triggered in certain circumstances such as if market values have significantly declined at the conclusion of the lease.

The table below shows the timing of the undiscounted cash outflows for the lease liabilities included on the balance sheet.

	\$ million	
	2019	2018 ^a
Undiscounted lease liability cash flows due:		
Within 1 year	2,514	98
1 to 2 years	1,839	97
2 to 3 years	1,364	95
3 to 4 years	1,105	94
4 to 5 years	876	86
5 to 10 years	2,427	309
Over 10 years	1,174	571
	11,299	1,350
Impact of discounting	(1,577)	(683)
Lease liabilities at 31 December	9,722	667
Of which – current	2,067	44
– non-current	7,655	623

^a Comparative information represents finance leases accounted for under IAS 17

The group may enter into lease arrangements a number of years before taking control of the underlying asset due to construction lead times or to secure future operational requirements. The total undiscounted amount for future commitments for leases not yet commenced as at 31 December 2019 is \$5,688 million. The majority of this future commitment relates to the floating LNG vessel to service the Greater Tortue Ahmeyim project from 2022.

	\$ million
	2019
Total cash outflow for amounts included in lease liabilities ^a	2,709
Expense for variable payments not included in the lease liability	67
Short-term lease expense	331
Additions to right-of-use assets in the period	2,542

^a The cash outflows for amounts not included in lease liabilities approximate the income statement expense disclosed above

An analysis of right-of-use assets and depreciation is provided in Note 12. An analysis of lease interest expense is provided in Note 7.

29. Financial instruments and financial risk factors

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

	\$ million				
At 31 December 2019	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	–	1,445	–	1,445
Loans		906	63	–	969
Trade and other receivables	20	24,271	–	–	24,271
Derivative financial instruments	30	–	9,984	483	10,467
Cash and cash equivalents	25	18,183	4,289	–	22,472
Financial liabilities					
Trade and other payables	22	(55,891)	–	–	(55,891)
Derivative financial instruments	30	–	(8,122)	(676)	(8,798)
Accruals		(6,062)	–	–	(6,062)
Lease liabilities	28	(9,722)	–	–	(9,722)
Finance debt ^a	26	(67,724)	–	–	(67,724)
		(96,039)	7,659	(193)	(88,573)

29. Financial instruments and financial risk factors – continued

					\$ 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)
Lease liabilities	28	(667)	—	—	(667)
Finance debt ^a	26	(65,132)	—	—	(65,132)
		(82,505)	4,668	(821)	(78,658)

^a As a result of the adoption of IFRS 16 'Leases', leases that were previously classified as finance leases under IAS 17 are now presented as 'Lease liabilities' on the group balance sheet and therefore do not form part of finance debt. Comparative information for finance debt and lease liabilities have been amended to be on a consistent basis with amounts presented for 2019. The previously disclosed amounts for finance debt for 2018 was \$65,799 million.

The fair value of finance debt is shown in Note 26. For all other financial instruments within the scope of IFRS 9, 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 \$129 million. Dividend income of \$20 million (2018 \$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.

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.

29. Financial instruments and financial risk factors – continued

(i) Commodity price risk

The group's integrated, supply and trading function is responsible for delivering value across the overall crude, oil products, gas and power supply chains. As such, it routinely enters into spot and term physical commodity contracts in addition to optimising physical storage, pipeline and transportation capacity. These activities expose the group to commodity price risk which is managed by entering into oil and natural gas swaps, options and futures.

The group measures market risk exposure arising from its trading positions in liquid periods using value-at-risk techniques based on Variance/Covariance or Monte Carlo simulation models. These techniques make a statistical assessment of the market risk arising from possible future changes in market prices over a one-day holding period within a 95% confidence level. The value-at-risk measure is supplemented by stress testing and scenario analysis through simulating the financial impact of certain physical, economic and geo-political scenarios. Trading activity occurring in liquid periods is subject to value-at-risk and other limits for each trading activity and the aggregate of all trading activity. The board has delegated a limit of \$100 million (2018 \$100 million) value at risk in support of this trading activity. Alternative measures are used to monitor exposures which are outside liquid periods and for which value-at-risk techniques are not appropriate.

(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 2019, the total foreign currency borrowings not swapped into US dollars amounted to \$219 million (2018 \$407 million excludes leases).

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 and Korean won. At 31 December 2019 the most significant open contracts in place were for \$106 million sterling (2018 \$434 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.

(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 2019 was 62% of total finance debt outstanding (2018 73% excludes leases). The weighted average interest rate on finance debt at 31 December 2019 was 3% (2018 4%) and the weighted average maturity of fixed rate debt was five years (2018 four years excludes leases).

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 2020, it is estimated that the group's finance costs for 2020 would change by approximately \$419 million (2018 \$475 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 2019 was \$692 million (2018 \$696 million) in respect of liabilities of joint ventures and associates and \$523 million (2018 \$432 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.

29. Financial instruments and financial risk factors – continued

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. Lifetime expected credit losses are recognized for trade receivables and the credit risk associated with the significant majority of financial assets measured at amortized cost is considered to be low. Since the tenor of substantially all of the group's in-scope financial assets is less than 12 months there is no significant difference between the measurement of 12-month and lifetime expected credit losses. Expected loss allowances for financial guarantee contracts are typically lower than their fair value less, where appropriate, amortization. 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 2019, the group had in place credit enhancements designed to mitigate approximately \$7.0 billion (2018 \$7.3 billion) of credit risk, of which substantially all 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	%	
	2019	2018
AAA to AA-	16%	22%
A+ to A-	51%	41%
BBB+ to BBB-	13%	16%
BB+ to BB-	7%	8%
B+ to B-	11%	11%
CCC+ and below	2%	2%

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.

	\$ million					
	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Related amounts not set off in the balance sheet			Net amount
			Net amounts presented on the balance sheet	Master netting arrangements	Cash collateral (received) pledged	
At 31 December 2019						
Derivative assets	13,191	(2,724)	10,467	(1,971)	(206)	8,290
Derivative liabilities	(11,445)	2,724	(8,721)	1,971	—	(6,750)
Trade and other receivables	10,661	(5,211)	5,450	(961)	(190)	4,299
Trade and other payables	(10,266)	5,211	(5,055)	961	—	(4,094)
At 31 December 2018						
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)

29. Financial instruments and financial risk factors – continued

(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.

The group benefits from open credit provided by suppliers who generally sell on five to 60-day payment terms in accordance with industry norms. BP utilizes various arrangements in order to manage its working capital and reduce volatility in cash flow. This includes discounting of receivables and, in the supply and trading business, managing inventory, collateral and supplier payment terms within a maximum of 60 days.

It is normal practice in the oil and gas supply and trading business for customers and suppliers to utilise letter of credit (LC) facilities to mitigate credit and non-performance risk. Consequently, LCs facilitate active trading in a global market where credit and performance risk can be significant. In common with the industry, BP routinely provides LCs to some of its suppliers.

The group has committed LC facilities totalling \$12,175 million (2018 \$12,175 million), allowing LCs to be issued for a maximum 24-month duration. There were also uncommitted secured LC facilities in place at 31 December 2019 for \$4,440 million (2018 \$4,190 million), which are secured against inventories or receivables when utilized. The facilities are held with over 20 international banks. The uncommitted secured LC facilities can only be terminated by either party giving a stipulated termination notice to the other.

In certain circumstances, the supplier has the option to request accelerated payment from the LC provider in order to further reduce their exposure. BP's payments are made to the provider of the LC rather than the supplier according to the original contractual payment terms. At 31 December 2019, \$4,755 million (2018 \$3,705 million) of the group's trade payables subject to these arrangements were payable to LC providers, with no material exposure to any individual provider.

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

During 2019, \$8 billion (2018 \$9 billion) of long-term taxable bonds were issued with terms ranging from one to thirty 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 2019 (2018 \$22.5 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2019, the group had substantial amounts of undrawn borrowing facilities available, consisting of \$7,625 million (2018 \$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. On 13th March the group entered into a committed \$10,000 million credit facility which is available for two years at pre-agreed margins.

The table below shows the timing of cash outflows relating to finance debt, trade and other payables and accruals.

	\$ million							
	2019				2018			
	Trade and other payables ^a	Accruals	Finance debt	Interest on finance debt	Trade and other payables ^a	Accruals	Finance debt ^b	Interest on finance debt ^b
Within one year	43,699	5,066	10,065	2,037	43,230	4,626	9,257	2,350
1 to 2 years	1,937	261	6,726	1,641	2,232	146	6,743	1,904
2 to 3 years	1,465	146	7,949	1,409	1,662	95	6,758	1,653
3 to 4 years	1,409	181	7,022	1,172	1,484	64	8,005	1,379
4 to 5 years	1,332	108	7,554	942	1,406	89	7,009	1,101
5 to 10 years	5,863	231	23,540	1,970	6,058	113	25,187	2,250
Over 10 years	3,957	69	2,497	249	5,001	68	983	9
	59,662	6,062	65,353	9,420	61,073	5,201	63,942	10,646

^a 2019 includes \$16,129 million (2018 \$18,360 million) in relation to the Gulf of Mexico oil spill, of which \$14,501 million (2018 \$16,058 million) matures in greater than one year.

^b As a result of the adoption of IFRS 16 'Leases', leases that were previously classified as finance leases under IAS 17 are now presented as 'Lease liabilities' on the group balance sheet and therefore do not form part of finance debt. Comparative information for finance debt and interest on finance debt has been amended to be on a consistent basis with amounts presented for 2019. \$667 million and \$683 million relating to finance lease liabilities have been excluded from the comparative information for finance debt and interest on finance debt respectively for 2018. The previously disclosed amounts for finance debt and interest on finance debt for 2018 was \$64,608 million and \$11,329 million respectively. The timing of cash outflows relating to lease liabilities reported on the balance sheet are now shown in Note 28.

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.

29. Financial instruments and financial risk factors – continued

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 \$24,787 million at 31 December 2019 (2018 \$22,453 million) to be received on the same day as the related cash outflows. For further information on our derivative financial instruments, see Note 30.

Cash outflows for derivative financial instruments at 31 December	\$ million	
	2019	2018
Within one year	1,678	1,700
1 to 2 years	2,384	1,678
2 to 3 years	2,838	2,384
3 to 4 years	2,906	2,838
4 to 5 years	3,321	2,906
5 to 10 years	10,633	11,475
Over 10 years	2,224	724
	25,984	23,705

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.

30. Derivative financial instruments – continued

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

	\$ million			
	2019		2018	
	Fair value asset	Fair value liability	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	81	(744)	69	(898)
Oil price derivatives	1,918	(1,478)	2,361	(1,849)
Natural gas price derivatives	6,569	(4,871)	4,787	(3,888)
Power price derivatives	1,306	(952)	1,240	(943)
Other derivatives	110	—	107	—
	9,984	(8,045)	8,564	(7,578)
Embedded derivatives				
Other embedded derivatives	—	(77)	—	(107)
	—	(77)	—	(107)
Cash flow hedges				
Currency forwards	1	(4)	5	(14)
Gas price futures	—	—	2	—
	1	(4)	7	(14)
Fair value hedges				
Currency swaps	344	(637)	158	(789)
Interest rate swaps	138	(35)	262	(445)
	482	(672)	420	(1,234)
	10,467	(8,798)	8,991	(8,933)
Of which – current	4,153	(3,261)	3,846	(3,308)
– non-current	6,314	(5,537)	5,145	(5,625)

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						
	2019						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	48	23	9	1	—	—	81
Oil price derivatives	1,619	114	76	53	45	11	1,918
Natural gas price derivatives	1,889	824	615	489	433	2,319	6,569
Power price derivatives	556	269	146	94	67	174	1,306
Other derivatives	33	—	—	77	—	—	110
	4,145	1,230	846	714	545	2,504	9,984

	\$ 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

30. Derivative financial instruments – continued

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

	\$ million						
	2019						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(166)	(283)	(201)	(1)	(23)	(70)	(744)
Oil price derivatives	(1,405)	(56)	(14)	(2)	(1)	—	(1,478)
Natural gas price derivatives	(1,070)	(522)	(446)	(399)	(363)	(2,071)	(4,871)
Power price derivatives	(395)	(165)	(104)	(76)	(51)	(161)	(952)
	(3,036)	(1,026)	(765)	(478)	(438)	(2,302)	(8,045)

	\$ 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)

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						
	2019						
	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	63	6	2	—	2	1	74
Level 2	5,344	1,014	439	210	120	42	7,169
Level 3	779	501	485	540	452	2,708	5,465
	6,186	1,521	926	750	574	2,751	12,708
Less: netting by counterparty	(2,041)	(291)	(80)	(36)	(29)	(247)	(2,724)
	4,145	1,230	846	714	545	2,504	9,984
Fair value of derivative liabilities							
Level 1	(49)	(8)	(4)	(1)	(2)	(1)	(65)
Level 2	(4,522)	(932)	(458)	(146)	(113)	(101)	(6,272)
Level 3	(506)	(377)	(383)	(367)	(352)	(2,447)	(4,432)
	(5,077)	(1,317)	(845)	(514)	(467)	(2,549)	(10,769)
Less: netting by counterparty	2,041	291	80	36	29	247	2,724
	(3,036)	(1,026)	(765)	(478)	(438)	(2,302)	(8,045)
Net fair value	1,109	204	81	236	107	202	1,939

	\$ 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

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 2019	23	(13)	(148)	107	(31)
Gains (losses) recognized in the income statement	128	82	244	2	456
Gains (losses) recognized in other comprehensive income	—	—	(18)	—	(18)
Settlements	(79)	(21)	(179)	—	(279)
Transfers out of level 3	(1)	(20)	(24)	1	(44)
Net fair value of contracts at 31 December 2019	71	28	(125)	110	84
Deferred day-one gains (losses)					949
Derivative asset (liability)					1,033

	\$ 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

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2019 was a \$250-million gain (2018 \$123-million gain related to derivatives still held at 31 December 2018).

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 was a net gain of \$2,153 million (2018 \$2,504 million net gain and 2017 \$1,983 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 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 gain of \$160 million (2018 \$351 million net loss and 2017 \$1,420 million net gain), 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 2019, 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 and foreign currency basis spreads 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, 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

During the period the group held Henry Hub NYMEX futures designated as hedging instruments in cash flow hedge relationships of certain highly probable forecast future sales. At 31 December 2019, these hedging instruments and highly probably forecast sales had been realised and the corresponding amounts recognised in the cash flow hedge reserve were released to the income statement during the period.

The group is exposed to the variability in the gas price, but only applied 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).

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

The hedge was highly effective due to the price index of the hedging instruments matching the price index of the hedged item. The group did not designate any net positions as hedged items in cash flow hedges of commodity price risk.

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

	\$ million		
	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)
At 31 December 2019			
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	(1)	1	—
Commodity price risk			
Highly probable forecast sales	(100)	100	—
At 31 December 2018			
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	(5)	5	—
Commodity price risk			
Highly probable forecast sales	(126)	126	—

The tables below summarize the carrying amount and nominal amount of the derivatives designated as hedging instruments in cash flow hedge relationships.

	Carrying amount of hedging instrument		Nominal amounts of hedging instruments	
	Assets	Liabilities	\$ million	mmBtu
At 31 December 2019				
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	1	(4)	150	
At 31 December 2018				
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 at 31 December relating to highly probably forecast capital expenditure \$150 million (2018 \$304 million) matures within 12 months and \$nil (2018 \$82 million) within one to two years. All of the hedging instruments relating to highly probable forecast sales at 31 December 2018 matured in 2019.

30. Derivative financial instruments – continued

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.

	Weighted average price/rate		
	2019	2018	
	Forecast capital expenditure	Forecast capital expenditure	Forecast sales
At 31 December			
Sterling/US dollar	1.35	1.34	
Euro/US dollar	1.11	1.14	
Australian dollar/US dollar	—	0.72	
Norwegian krone/US dollar	—	8.67	
Korean won/US dollar	1,115.66	1,107.90	
Henry Hub \$/mmBtu			2.86

Fair value hedges

At 31 December 2019, 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, 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 tables below summarize the change in the fair value of hedging instruments and the hedged item used to calculate ineffectiveness in the period. The signage convention for changes in fair value presented in this table is consistent with that presented in Note 27.

	\$ million		
	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)
At 31 December 2019			
Fair value hedges			
Interest rate risk on finance debt	(764)	737	27
Interest rate and foreign currency risk on finance debt	(336)	286	50
At 31 December 2018			
Fair value hedges			
Interest rate risk on finance debt	(70)	69	(1)
Interest rate and foreign currency risk on finance debt	812	(809)	3

30. Derivative financial instruments – continued

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

		\$ million		
		Carrying amount of hedging instrument		Nominal amounts of hedging instruments
		Assets	Liabilities	
At 31 December 2019				
Fair value hedges				
Interest rate risk on finance debt		138	(35)	13,442
Interest rate and foreign currency risk on finance debt		344	(637)	21,296
At 31 December 2018				
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 tables below summarize the profile by tenor of the nominal amount of the derivatives designated as hedging instruments in fair value hedge relationships at 31 December. The weighted average floating interest rate of these interest rate swaps and cross-currency interest rate swaps was 2.36% (2018 3.04%) and 3.27% (2018 4.07%) respectively.

		\$ million							
		Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	5-10 years	Over 10 years	Total
At 31 December 2019									
Fair value hedges									
Interest rate risk on finance debt		3,000	2,576	4,039	1,200	206	2,421	—	13,442
Interest rate and foreign currency risk on finance debt		882	672	1,400	2,777	3,109	10,216	2,240	21,296
At 31 December 2018									
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

The tables below summarize 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.

		\$ million				
		Carrying amount of hedged item		Accumulated fair value adjustment included in the carrying amount of hedged items		
		Assets	Liabilities	Assets	Liabilities	Discontinued hedges
At 31 December 2019						
Fair value hedges						
Interest rate risk on finance debt		—	(13,441)	—	(100)	(714)
Interest rate and foreign currency risk on finance debt		—	(21,240)	—	(525)	—
At 31 December 2018						
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.

30. Derivative financial instruments – continued

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	Total
	Highly probable forecast capital expenditure	Highly probable forecast sales	Purchase of equity ^a	Interest rate and foreign currency risk on finance debt	
At 1 January 2019	(21)	(6)	(651)	(223)	(901)
Recognized in other comprehensive income					
Cash flow hedges marked to market	(3)	(100)	—	—	(103)
Cash flow hedges reclassified to the income statement- hedged item affected profit or loss	—	106	—	—	106
Costs of hedging marked to market	—	—	—	(4)	(4)
Costs of hedging reclassified to the income statement	—	—	—	57	57
	(3)	6	—	53	56
Cash flow hedges transferred to the balance sheet	23	—	—	—	23
At 31 December 2019	(1)	—	(651)	(170)	(822)

	\$ million				
	Cash flow hedge reserve			Costs of hedging reserve	Total
	Highly probable forecast capital expenditure	Highly probable forecast sales	Purchase of equity ^a	Interest rate and foreign currency risk on finance debt	
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:

	2019		2018		2017	
	Shares thousand	\$ million	Shares thousand	\$ million	Shares thousand	\$ million
Issued						
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	21,525,464	5,381	21,288,193	5,322	21,049,696	5,263
Issue of new shares for the scrip dividend programme	208,927	52	195,305	49	289,789	72
Issue of new shares for employee share-based payment plans	37,400	9	92,168	23	—	—
Issue of new shares – other	—	—	—	—	—	—
Repurchase of ordinary share capital	(235,951)	(59)	(50,202)	(13)	(51,292)	(13)
At 31 December	21,535,840	5,383	21,525,464	5,381	21,288,193	5,322
		5,404		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 2019 the company repurchased 236 million ordinary shares for a total consideration of \$1,511 million, including transaction costs of \$8 million, as part of the share repurchase programme announced on 31 October 2017. All shares purchased were for cancellation. The repurchased shares represented 1.1% of ordinary share capital. A further 120 million of shares have been repurchased in January 2020 at a total cost of \$776 million. The number of shares in issue is reduced when shares are repurchased.

Treasury shares^a

	2019		2018		2017	
	Shares thousand	Nominal value \$ million	Shares thousand	Nominal value \$ million	Shares thousand	Nominal value \$ million
At 1 January	1,426,265	356	1,482,072	370	1,614,657	403
Purchases for settlement of employee share plans	1,118	—	757	—	4,423	1
Issue of new shares for employee share-based payment plans	37,400	9	92,168	23	—	—
Shares re-issued for employee share-based payment plans	(167,927)	(42)	(148,732)	(37)	(137,008)	(34)
At 31 December	1,296,856	323	1,426,265	356	1,482,072	370
Of which – shares held in treasury by BP	1,163,077	290	1,264,732	316	1,472,343	368
– shares held in ESOP trusts	133,707	33	161,518	40	9,705	2
– shares held by BP's US share plan administrator ^b	72	—	15	—	24	—

^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 5.9% (2018 6.9% and 2017 7.5%) of the called-up ordinary share capital of the company.

During 2019, the movement in shares held in treasury by BP represented less than 0.5% (2018 less than 1.0% and 2017 less than 0.5%) of the ordinary share capital of the company.

32. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 31 December 2018	5,402	12,305	1,439	27,206	46,352
Adjustment on adoption of IFRS 16, net of tax	—	—	—	—	—
At 1 January 2019	5,402	12,305	1,439	27,206	46,352
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	52	(52)	—	—	—
Cash flow hedges transferred to the balance sheet, net of tax	—	—	—	—	—
Repurchases of ordinary share capital	(59)	—	59	—	—
Share-based payments, net of tax ^b	9	164	—	—	173
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
Transactions involving non-controlling interests, net of tax ^c	—	—	—	—	—
At 31 December 2019	5,404	12,417	1,498	27,206	46,525
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
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 ^d	—	—	—	—	—
At 31 December 2017	5,343	12,147	1,426	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
(15,767)	(8,902)	—	(777)	(210)	(987)	78,748	99,444	2,104	101,548
—	—	—	—	—	—	(329)	(329)	(1)	(330)
(15,767)	(8,902)	—	(777)	(210)	(987)	78,419	99,115	2,103	101,218
—	—	—	—	—	—	4,026	4,026	164	4,190
—	2,407	—	—	—	—	—	2,407	9	2,416
—	—	—	5	50	55	—	55	—	55
—	—	—	—	—	—	82	82	—	82
—	—	—	—	—	—	(64)	(64)	—	(64)
—	—	—	—	—	—	171	171	—	171
—	—	—	(3)	—	(3)	—	(3)	—	(3)
—	2,407	—	2	50	52	4,215	6,674	173	6,847
—	—	—	—	—	—	(6,929)	(6,929)	(213)	(7,142)
—	—	—	23	—	23	—	23	—	23
—	—	—	—	—	—	(1,511)	(1,511)	—	(1,511)
1,355	—	—	—	—	—	(809)	719	—	719
—	—	—	—	—	—	5	5	—	5
—	—	—	—	—	—	316	316	233	549
(14,412)	(6,495)	—	(752)	(160)	(912)	73,706	98,412	2,296	100,708
(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
(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

^c Principally relates to the sale of a 49% interest in BP's retail property portfolio in Australia.

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

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		
	2019		
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	2,418	(2)	2,416
Cash flow hedges (including reclassifications)	6	(1)	5
Costs of hedging (including reclassifications)	53	(3)	50
Share of items relating to equity-accounted entities, net of tax	82	—	82
Other	—	(64)	(64)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	328	(157)	171
Cash flow hedges that will subsequently be transferred to the balance sheet	(3)	—	(3)
Other comprehensive income	2,884	(227)	2,657

	\$ 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

33. Contingent liabilities

There were contingent liabilities at 31 December 2019 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, BP group entities are subject to legal and regulatory proceedings 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, climate change and environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. The amounts claimed 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, BP expects that the impact of current 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, in aggregate, 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, BP does not expect there to 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 costs are inherently difficult to estimate. However, the estimated cost of environmental obligations has been provided in these accounts in accordance with the group's accounting policies. While the amounts of future possible costs that are not provided for could be significant and 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 319-320.

Contingent liabilities related to the Gulf of Mexico oil spill

For information on legal proceedings relating to the Deepwater Horizon oil spill, see Legal proceedings on pages 319-320. Any further outstanding Deepwater Horizon related claims are not expected to have a material impact on the group's financial performance.

34. Remuneration of senior management and non-executive directors

Remuneration of directors

	\$ million		
	2019	2018	2017
Total for all directors			
Emoluments	9	8	9
Amounts received under incentive schemes ^a	20	16	9
Total	29	24	18

^a Excludes amounts relating to past directors.

Emoluments

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

Pension contributions

During 2019 one executive director participated in a UK final salary pension plan in respect of service prior to 1 April 2011. During 2019, 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 100. See also Related-party transactions on page 321.

Remuneration of directors and senior management

	\$ million		
	2019	2018	2017
Total for all senior management and non-executive directors			
Short-term employee benefits	30	25	29
Pensions and other post-retirement benefits	2	2	2
Share-based payments	32	32	29
Total	64	59	60

Senior management comprises members of the executive team, see pages 78-79 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 2019 (2018 \$nil and 2017 \$nil).

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

	\$ million		
	2019	2018	2017
Employee costs			
Wages and salaries ^a	7,497	7,931	7,572
Social security costs	733	743	711
Share-based payments ^b	694	669	624
Pension and other post-retirement benefit costs	948	1,154	1,296
	9,872	10,497	10,203

	2019			2018			2017		
	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
Average number of employees ^c									
Upstream	5,800	11,000	16,800	5,900	11,500	17,400	6,200	12,200	18,400
Downstream ^d	5,700	37,300	43,000	6,000	36,300	42,300	6,100	35,900	42,000
Other businesses and corporate ^e	2,100	10,600	12,700	1,900	12,100	14,000	1,900	12,400	14,300
	13,600	58,900	72,500	13,800	59,900	73,700	14,200	60,500	74,700

^a Includes termination costs of \$182 million (2018 \$493 million and 2017 \$189 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 18,100 (2018 17,100 and 2017 16,500) service station staff.

^e Includes 2,500 (2018 4,000 and 2017 4,700) agricultural, operational and seasonal workers in Brazil.

36. Auditor's remuneration

	\$ million		
	2019	2018	2017
Fees			
The audit of the company annual accounts ^a	32	25	26
The audit of accounts of subsidiaries of the company	11	10	11
Total audit	43	35	37
Audit-related assurance services ^b	4	4	7
Total audit and audit-related assurance services	47	39	44
Non-audit and other assurance services	1	2	3
Total non-audit or non-audit-related assurance services	1	2	3
Services relating to BP pension plans	1	1	—
	49	42	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 years ended 31 December 2019 and 31 December 2018 thus relates to Deloitte and for the year ended 31 December 2017 EY.

2019 includes \$3.6 million of additional fees for 2018. 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. Auditor's remuneration is included in the income statement within distribution and administration expenses.

Tax services (in relation to income tax, indirect tax compliance, employee tax services and tax advisory services) were \$nil in all periods presented.

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 \$49 million (2018 \$42 million and 2017 \$47 million) is required to be presented as follows: audit \$43 million (2018 \$35 million and 2017 \$37 million); other audit-related \$4 million (2018 \$4 million and 2017 \$7 million); tax \$nil (2018 \$nil and 2017 \$nil); and all other fees \$3 million (2018 \$3 million and 2017 \$3 million).

37. Subsidiaries, joint arrangements and associates

The more important subsidiaries and associates of the group at 31 December 2019 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			
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. As described in Note 2, in 2020 BP expects, subject to governmental authorizations, to complete the sale of all of its Alaska operations, including its interest in BP Exploration (Alaska) Inc., to Hilcorp Energy. Following completion of the sale, BP will continue to fully and unconditionally guarantee the payment obligations of BP Exploration (Alaska) Inc. to 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				
	2019				
	Issuer		Guarantor		
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,413	—	278,111	(4,127)	278,397
Earnings from joint ventures- after interest and tax	—	—	576	—	576
Earnings from associates- after interest and tax	—	—	2,681	—	2,681
Equity-accounted income of subsidiaries- after interest and tax	—	5,916	—	(5,916)	—
Interest and other income	42	385	2,284	(1,942)	769
Gains on sale of businesses and fixed assets	4	—	189	—	193
Total revenues and other income	4,459	6,301	283,841	(11,985)	282,616
Purchases	2,361	—	211,438	(4,127)	209,672
Production and manufacturing expenses	907	—	20,908	—	21,815
Production and similar taxes	163	—	1,384	—	1,547
Depreciation, depletion and amortization	169	—	17,611	—	17,780
Impairment and losses on sale of businesses and fixed assets	747	—	7,328	—	8,075
Exploration expense	—	—	964	—	964
Distribution and administration expenses	75	803	10,333	(154)	11,057
Profit (loss) before interest and taxation	37	5,498	13,875	(7,704)	11,706
Finance costs	17	1,569	3,691	(1,788)	3,489
Net finance (income) expense relating to pensions and other post-retirement benefits	—	(153)	216	—	63
Profit (loss) before taxation	20	4,082	9,968	(5,916)	8,154
Taxation	(40)	56	3,948	—	3,964
Profit (loss) for the year	60	4,026	6,020	(5,916)	4,190
Attributable to					
BP shareholders	60	4,026	5,856	(5,916)	4,026
Non-controlling interests	—	—	164	—	164
	60	4,026	6,020	(5,916)	4,190

38. Condensed consolidating information on certain US subsidiaries – continued

Income statement continued

	\$ 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

Income statement continued

	\$ million				
	2017				
	Issuer	Guarantor			
	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

	\$ million				
	2019				
	Issuer	Guarantor		Eliminations and reclassifications	
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries		BP group
Profit (loss) for the year	60	4,026	6,020	(5,916)	4,190
Other comprehensive income					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences	—	200	1,338	—	1,538
Exchange (gains) or losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	—	—	880	—	880
Cash flow hedges marked to market	—	—	(100)	—	(100)
Cash flow hedges- recycled to the income statement	—	—	106	—	106
Costs of hedging market to market	—	—	(4)	—	(4)
Costs of hedging reclassified to the income statement	—	—	57	—	57
Share of items relating to equity-accounted entities, net of tax	—	—	82	—	82
Income tax relating to items that may be reclassified	—	—	(70)	—	(70)
	—	200	2,289	—	2,489
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	732	(404)	—	328
Cash flow hedges that will subsequently be transferred to the balance sheet	—	—	(3)	—	(3)
Income tax relating to items that will not be reclassified	—	(331)	174	—	(157)
	—	401	(233)	—	168
Other comprehensive income	—	601	2,056	—	2,657
Equity-accounted other comprehensive income of subsidiaries	—	2,047	—	(2,047)	—
Total comprehensive income	60	6,674	8,076	(7,963)	6,847
Attributable to					
BP shareholders	60	6,674	7,903	(7,963)	6,674
Non-controlling interests	—	—	173	—	173
	60	6,674	8,076	(7,963)	6,847

Statement of comprehensive income continued

	\$ million				
	2018				
	Issuer	Guarantor		Eliminations and reclassifications	
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries		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

38. Condensed consolidating information on certain US subsidiaries – continued

Statement of comprehensive income continued

	\$ million				
	2017				
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	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

38. Condensed consolidating information on certain US subsidiaries – continued

Balance sheet

	\$ million				
	2019				
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	—	—	132,642	—	132,642
Goodwill	—	—	11,868	—	11,868
Intangible assets	—	—	15,539	—	15,539
Investments in joint ventures	—	—	9,991	—	9,991
Investments in associates	—	2	20,332	—	20,334
Other investments	—	—	1,276	—	1,276
Subsidiaries- equity-accounted basis	—	167,895	—	(167,895)	—
Fixed assets	—	167,897	191,648	(167,895)	191,650
Loans	—	—	32,524	(31,894)	630
Trade and other receivables	—	2,771	2,147	(2,771)	2,147
Derivative financial instruments	—	—	6,314	—	6,314
Prepayments	—	—	781	—	781
Deferred tax assets	—	—	4,560	—	4,560
Defined benefit pension plan surpluses	—	6,588	465	—	7,053
	—	177,256	238,439	(202,560)	213,135
Current assets					
Loans	—	—	339	—	339
Inventories	44	—	20,836	—	20,880
Trade and other receivables	690	135	42,157	(18,540)	24,442
Derivative financial instruments	—	—	4,153	—	4,153
Prepayments	—	—	857	—	857
Current tax receivable	45	—	1,237	—	1,282
Other investments	—	—	169	—	169
Cash and cash equivalents	—	—	22,472	—	22,472
	779	135	92,220	(18,540)	74,594
Assets classified as held for sale	5,023	—	2,442	—	7,465
	5,802	135	94,662	(18,540)	82,059
Total assets	5,802	177,391	333,101	(221,100)	295,194
Current liabilities					
Trade and other payables	436	17,986	46,947	(18,540)	46,829
Derivative financial instruments	—	—	3,261	—	3,261
Accruals	347	21	4,698	—	5,066
Lease liabilities	—	—	2,067	—	2,067
Finance debt	—	—	10,487	—	10,487
Current tax payable	—	—	2,039	—	2,039
Provisions	—	—	2,453	—	2,453
	783	18,007	71,952	(18,540)	72,202
Liabilities directly associated with assets classified as held for sale	706	—	687	—	1,393
	1,489	18,007	72,639	(18,540)	73,595
Non-current liabilities					
Other payables	—	31,927	15,364	(34,665)	12,626
Derivative financial instruments	—	—	5,537	—	5,537
Accruals	—	—	996	—	996
Lease liabilities	—	—	7,655	—	7,655
Finance debt	—	—	57,237	—	57,237
Deferred tax liabilities	456	2,293	7,001	—	9,750
Provisions	114	—	18,384	—	18,498
Defined benefit pension plan and other post-retirement benefit plan deficits	—	202	8,390	—	8,592
	570	34,422	120,564	(34,665)	120,891
Total liabilities	2,059	52,429	193,203	(53,205)	194,486
Net assets	3,743	124,962	139,898	(167,895)	100,708
Equity					
BP shareholders' equity	3,743	124,962	137,602	(167,895)	98,412
Non-controlling interests	—	—	2,296	—	2,296
	3,743	124,962	139,898	(167,895)	100,708

38. Condensed consolidating information on certain US subsidiaries – continued

Balance sheet continued

	\$ 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
Lease liabilities	—	—	44	—	44
Finance debt	—	—	9,329	—	9,329
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
Lease liabilities	—	—	623	—	623
Finance debt	—	—	55,803	—	55,803
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

Cash flow statement

	\$ million				
	2019				
	Issuer	Guarantor		Eliminations and reclassifications	
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries		BP group
Operating activities					
Profit (loss) before taxation	20	4,082	9,968	(5,916)	8,154
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities					
Exploration expenditure written off	—	—	631	—	631
Depreciation, depletion and amortization	169	—	17,611	—	17,780
Impairment and (gain) loss on sale of businesses and fixed assets	743	—	7,139	—	7,882
Earnings from joint ventures and associates	—	—	(3,257)	—	(3,257)
Dividends received from joint ventures and associates	—	—	1,962	—	1,962
Equity accounted income of subsidiaries- after interest and tax	—	(5,916)	—	5,916	—
Dividends received from subsidiaries	—	6,360	—	(6,360)	—
Interest receivable	(1)	—	(2,228)	1,788	(441)
Interest received	1	12	2,191	(1,788)	416
Finance costs	17	—	5,260	(1,788)	3,489
Interest paid	(6)	—	(4,652)	1,788	(2,870)
Net finance expense relating to pensions and other post-retirement benefits	—	(153)	216	—	63
Share-based payments	—	739	(9)	—	730
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	—	(10)	(228)	—	(238)
Net charge for provisions, less payments	21	—	(197)	—	(176)
(Increase) decrease in inventories	(31)	—	(3,375)	—	(3,406)
(Increase) decrease in other current and non-current assets	(132)	(155)	(2,048)	—	(2,335)
Increase (decrease) in other current and non-current liabilities	1,954	3,469	(2,600)	—	2,823
Income taxes paid	(444)	(1)	(4,992)	—	(5,437)
Net cash provided by (used in) operating activities	2,311	8,427	21,392	(6,360)	25,770
Investing activities					
Expenditure on property, plant and equipment, intangible and other assets	(173)	—	(15,245)	—	(15,418)
Acquisitions, net of cash acquired	—	—	(3,562)	—	(3,562)
Investment in joint ventures	—	—	(137)	—	(137)
Investment in associates	—	—	(304)	—	(304)
Total cash capital expenditure	(173)	—	(19,248)	—	(19,421)
Proceeds from disposals of fixed assets	19	—	481	—	500
Proceeds from disposals of businesses, net of cash disposed	—	—	1,701	—	1,701
Proceeds from loan repayments	21	—	225	—	246
Net cash provided by (used in) investing activities	(133)	—	(16,841)	—	(16,974)
Financing activities					
Repurchase of shares	—	(1,511)	—	—	(1,511)
Lease liability payments	(46)	—	(2,326)	—	(2,372)
Proceeds from long-term financing	—	—	8,597	—	8,597
Repayments of long-term financing	—	—	(7,118)	—	(7,118)
Net increase (decrease) in short-term debt	—	—	180	—	180
Net increase (decrease) in non-controlling interests	—	—	566	—	566
Dividends paid					
BP shareholders	(2,132)	(6,929)	(4,245)	6,360	(6,946)
Non-controlling interests	—	—	(213)	—	(213)
Net cash provided by (used in) financing activities	(2,178)	(8,440)	(4,559)	6,360	(8,817)
Currency translation differences relating to cash and cash equivalents	—	—	25	—	25
Increase (decrease) in cash and cash equivalents	—	(13)	17	—	4
Cash and cash equivalents at beginning of year	—	13	22,455	—	22,468
Cash and cash equivalents at end of year	—	—	22,472	—	22,472

38. Condensed consolidating information on certain US subsidiaries – continued

Cash flow statement continued

	\$ million				
	2018				
	Issuer	Guarantor			
	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 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)
Lease liability payments	—	—	(35)	—	(35)
Proceeds from long-term financing	—	—	9,038	—	9,038
Repayments of long-term financing	—	—	(7,175)	—	(7,175)
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

	\$ million				
	2017				
	Issuer	Guarantor			
	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 (paid to) 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)
Lease liability payments	—	—	(45)	—	(45)
Proceeds from long-term financing	—	—	8,712	—	8,712
Repayments of long-term financing	—	—	(6,231)	—	(6,231)
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

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 308-313.

Oil and natural gas exploration and production activities

	\$ million									
	2019									
	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	31,655	—	67,319	3,421	15,194	48,150	—	42,629	6,300	214,668
Unproved properties	425	—	3,106	2,547	3,262	3,495	—	1,865	606	15,306
	32,080	—	70,425	5,968	18,456	51,645	—	44,494	6,906	229,974
Accumulated depreciation	18,481	—	35,379	409	9,922	35,572	—	22,481	3,924	126,168
Net capitalized costs	13,599	—	35,046	5,559	8,534	16,073	—	22,013	2,982	103,806
Costs incurred for the year ended 31 December^{a b}										
Acquisition of properties										
Proved	2	—	5	—	—	—	—	188	—	195
Unproved	13	—	50	1	220	18	—	—	—	302
	15	—	55	1	220	18	—	188	—	497
Exploration and appraisal costs ^c	128	—	271	15	220	417	2	171	61	1,285
Development	717	—	4,047	33	737	2,530	—	2,614	137	10,815
Total costs	860	—	4,373	49	1,177	2,965	2	2,973	198	12,597
Results of operations for the year ended 31 December^a										
Sales and other operating revenues ^d										
Third parties	229	—	1,780	274	1,620	2,736	2	1,588	1,142	9,371
Sales between businesses	2,345	—	10,785	1	142	2,815	—	7,596	554	24,238
	2,574	—	12,565	275	1,762	5,551	2	9,184	1,696	33,609
Exploration expenditure	157	—	233	13	124	222	2	187	26	964
Production costs	607	—	2,742	118	437	1,045	—	961	131	6,041
Production taxes	(75)	—	315	—	293	—	—	951	63	1,547
Other costs (income) ^e	(308)	—	2,527	67	92	33	42	(124)	153	2,482
Depreciation, depletion and amortization	1,383	—	4,456	118	1,056	3,806	2	2,384	297	13,502
Net impairments and (gains) losses on sale of businesses and fixed assets	483	(10)	5,726	(1)	160	151	—	1	—	6,510
	2,247	(10)	15,999	315	2,162	5,257	46	4,360	670	31,046
Profit (loss) before taxation ^f	327	10	(3,434)	(40)	(400)	294	(44)	4,824	1,026	2,563
Allocable taxes	(141)	—	(776)	(76)	(234)	593	(8)	3,078	392	2,828
Results of operations	468	10	(2,658)	36	(166)	(299)	(36)	1,746	634	(265)
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax										
Exploration and production activities – subsidiaries (as above)	327	10	(3,434)	(40)	(400)	294	(44)	4,824	1,026	2,563
Midstream and other activities – subsidiaries ^g	749	(26)	(363)	442	194	(19)	11	766	9	1,763
Equity-accounted entities ^h	(6)	70	23	—	65	82	2,460	213	—	2,907
Total replacement cost profit (loss) before interest and tax	1,070	54	(3,774)	402	(141)	357	2,427	5,803	1,035	7,233

^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 and other government take. The UK region includes a \$361-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 \$439 million which is included in finance costs in the group income statement.

^g Midstream and other activities excludes inventory holding gains and losses.

^h The profits of equity-accounted entities are included after interest and tax.

Oil and natural gas exploration and production activities – continued

	\$ million								
	2019								
	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	—	4,078	—	—	10,376	—	29,883	—	44,337
Unproved properties	—	768	—	—	93	—	1,120	—	1,981
	—	4,846	—	—	10,469	—	31,003	—	46,318
Accumulated depreciation	—	1,046	—	—	5,078	—	9,248	—	15,372
Net capitalized costs	—	3,800	—	—	5,391	—	21,755	—	30,946
Costs incurred for the year ended 31 December^{b,d,e}									
Acquisition of properties ^c									
Proved	—	—	—	—	—	—	—	—	—
Unproved	—	—	—	—	—	—	58	—	58
	—	—	—	—	—	—	58	—	58
Exploration and appraisal costs ^d	—	120	—	—	19	—	198	—	337
Development	—	640	—	—	675	—	3,076	—	4,391
Total costs	—	760	—	—	694	—	3,332	—	4,786
Results of operations for the year ended 31 December^b									
Sales and other operating revenues ^f									
Third parties	—	1,002	—	—	1,621	—	—	—	2,623
Sales between businesses	—	—	—	—	—	—	15,979	—	15,979
	—	1,002	—	—	1,621	—	15,979	—	18,602
Exploration expenditure	—	92	—	—	43	—	73	—	208
Production costs	—	216	—	—	465	—	1,535	—	2,216
Production taxes	—	—	—	—	343	—	7,861	—	8,204
Other costs (income)	—	59	—	—	16	—	358	—	433
Depreciation, depletion and amortization	—	323	—	—	414	—	1,773	—	2,510
Net impairments and losses on sale of businesses and fixed assets	—	—	—	—	(42)	—	49	—	7
	—	690	—	—	1,239	—	11,649	—	13,578
Profit (loss) before taxation	—	312	—	—	382	—	4,330	—	5,024
Allocable taxes	—	229	—	—	245	—	848	—	1,322
Results of operations	—	83	—	—	137	—	3,482	—	3,702
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)	—	83	—	—	137	—	3,482	—	3,702
Midstream and other activities after tax ^g	(6)	(13)	23	—	(72)	82	(1,022)	213	(795)
Total replacement cost profit (loss) after interest and tax	(6)	70	23	—	65	82	2,460	213	2,907

^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 sales tax.

^g Includes interest and adjustment for non-controlling interests. Excludes inventory holding gains and losses.

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	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 taxes.

^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 Bidas 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	—	—	55	—	638	—	—	714
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	—	—	1,277	—	11,545	346	—	13,781
Profit (loss) before taxation	—	501	—	—	515	—	4,356	7	—	5,379
Allocable taxes	—	350	—	—	321	—	849	—	—	1,520
Results of operations ^g	—	151	—	—	194	—	3,507	7	—	3,859
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	—	—	194	—	3,507	7	—	3,859
Midstream and other activities after tax ^h	(2)	(21)	28	—	15	207	(1,161)	238	—	(696)
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 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 Bidas 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

	\$ million									
	2017									
	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	34,208	—	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	—	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 Bidas 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.

Oil and natural gas exploration and production activities – continued

									\$ 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 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.

Movements in estimated net proved reserves

million barrels										
2019										
Crude oil ^{a,b}	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US ^{c,d}	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	(23)	—	72	(8)	1	39	—	104	2	187
Improved recovery	—	—	189	1	—	—	—	—	—	191
Purchases of reserves-in-place	—	—	—	—	—	—	—	1	—	1
Discoveries and extensions	—	—	34	—	—	—	—	11	—	45
Production	(36)	—	(143)	(9)	(3)	(57)	—	(125)	(6)	(378)
Sales of reserves-in-place	—	—	(12)	—	—	(45)	—	—	—	(57)
	(59)	—	141	(16)	(2)	(63)	—	(9)	(4)	(12)
At 31 December ^e										
Developed	206	—	1,063	40	7	156	—	1,074	26	2,572
Undeveloped	200	—	842	179	5	40	—	525	4	1,794
	406	—	1,905	218	12	196	—	1,599	30	4,367
Equity-accounted entities (BP share)^f										
At 1 January										
Developed	—	57	—	—	293	1	3,190	—	—	3,541
Undeveloped	—	100	—	19	259	—	2,414	—	—	2,792
	—	157	—	19	552	1	5,604	—	—	6,333
Changes attributable to										
Revisions of previous estimates	—	2	—	1	(13)	1	158	—	—	147
Improved recovery	—	4	—	—	—	—	—	—	—	4
Purchases of reserves-in-place	—	—	—	—	—	—	7	—	—	7
Discoveries and extensions	—	—	—	—	33	—	277	—	—	310
Production	—	(13)	—	—	(24)	—	(345)	—	—	(382)
Sales of reserves-in-place	—	—	—	—	—	—	(6)	—	—	(6)
	—	(7)	—	1	(4)	1	91	—	—	81
At 31 December ^{g,h}										
Developed	—	115	—	—	291	2	3,159	—	—	3,567
Undeveloped	—	35	—	20	257	—	2,535	—	—	2,847
	—	150	—	20	548	2	5,695	—	—	6,415
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	206	115	1,063	40	298	158	3,159	1,074	26	6,140
Undeveloped	200	35	842	198	262	40	2,535	525	4	4,642
	406	150	1,905	238	560	198	5,695	1,599	30	10,781

^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 4.5 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 362 million barrels of crude oil associated with Assets Held for Sale in the USA.

^e Includes 4 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 346 million barrels of crude oil in respect of the 6.17% non-controlling interest in Rosneft, including 26 mmbbl held through BP's interests in Russia other than Rosneft.

^h Total proved crude oil reserves held as part of our equity interest in Rosneft is 5,604 million barrels, comprising less than 1 million barrels in Egypt, Vietnam, Iraq and Canada, 35 million barrels in Venezuela and 5,568 million barrels in Russia.

Movements in estimated net proved reserves - continued

million barrels										
2019										
Total liquids ^{a,b}	Europe		North America		South America	Africa	Asia	Australasia		Total
	UK	Rest of Europe	US ^{c,d}	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	(24)	—	26	(8)	—	40	—	104	2	140
Improved recovery	1	—	252	1	—	—	—	—	—	254
Purchases of reserves-in-place	—	—	—	—	—	—	—	1	—	1
Discoveries and extensions	—	—	35	—	—	—	—	11	—	46
Production ^e	(38)	—	(176)	(9)	(6)	(60)	—	(125)	(7)	(420)
Sales of reserves-in-place	—	—	(28)	—	—	(45)	—	—	—	(74)
	(60)	—	109	(16)	(6)	(65)	—	(9)	(5)	(52)
At 31 December ^f										
Developed	214	—	1,292	40	9	168	—	1,074	30	2,828
Undeveloped	205	—	1,092	179	26	43	—	525	4	2,074
	420	—	2,384	218	35	212	—	1,599	34	4,902
Equity-accounted entities (BP share)^g										
At 1 January										
Developed	—	60	—	—	293	8	3,293	—	—	3,655
Undeveloped	—	104	—	19	259	—	2,465	—	—	2,846
	—	164	—	19	552	8	5,758	—	—	6,502
Changes attributable to										
Revisions of previous estimates	—	2	—	1	(11)	7	146	—	—	145
Improved recovery	—	5	—	—	—	—	—	—	—	5
Purchases of reserves-in-place	—	—	—	—	—	—	7	—	—	7
Discoveries and extensions	—	—	—	—	33	—	277	—	—	310
Production	—	(14)	—	—	(24)	(2)	(346)	—	—	(386)
Sales of reserves-in-place	—	—	—	—	—	—	(6)	—	—	(6)
	—	(7)	—	1	(1)	5	78	—	—	75
At 31 December ^{h,i}										
Developed	—	120	—	—	293	13	3,248	—	—	3,675
Undeveloped	—	37	—	20	257	—	2,588	—	—	2,902
	—	157	—	20	550	13	5,836	—	—	6,576
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	214	120	1,292	40	302	181	3,248	1,074	30	6,502
Undeveloped	205	37	1,092	198	283	43	2,588	525	4	4,976
	420	157	2,384	238	585	224	5,836	1,599	34	11,478

^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 4.5 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 Includes 456 million barrels associated with Assets Held for Sale in the USA.

^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 11 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 357 million barrels in respect of the non-controlling interest in Rosneft, including 26 mmbbl held through BP's interests in Russia other than Rosneft.

ⁱ Total proved liquid reserves held as part of our equity interest in Rosneft is 5,745 million barrels, comprising 35 million barrels in Venezuela, less than 1 million barrels in Iraq, Canada, Egypt and Vietnam and 5,709 million barrels in Russia.

Movements in estimated net proved reserves – continued

		billion cubic feet							2019		
Natural gas ^{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			
Subsidiaries											
At 1 January											
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
Changes attributable to											
Revisions of previous estimates		(34)	—	(1,877)	1	(263)	(4)	—	285	(129)	(2,022)
Improved recovery		9	—	307	—	—	—	—	—	—	315
Purchases of reserves-in-place		—	—	—	—	—	—	—	50	—	50
Discoveries and extensions		—	—	11	—	178	—	—	299	—	488
Production ^d		(57)	—	(923)	(1)	(729)	(450)	—	(383)	(291)	(2,834)
Sales of reserves-in-place		—	—	(386)	—	—	(21)	—	—	—	(406)
		(82)	—	(2,869)	—	(814)	(475)	—	251	(420)	(4,410)
At 31 December ^e											
Developed		493	—	6,330	—	2,192	1,163	—	3,667	2,256	16,101
Undeveloped		207	—	2,127	—	2,235	742	—	3,401	1,132	9,844
		700	—	8,458	—	4,427	1,905	—	7,068	3,389	25,946
Equity-accounted entities (BP share)^f											
At 1 January											
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
Changes attributable to											
Revisions of previous estimates		—	9	—	3	(120)	38	789	—	—	718
Improved recovery		—	15	—	—	—	—	—	—	—	15
Purchases of reserves-in-place		—	—	—	—	—	—	—	—	—	—
Discoveries and extensions		—	—	—	—	180	—	534	—	—	714
Production ^d		—	(22)	—	—	(135)	(65)	(448)	(5)	—	(676)
Sales of reserves-in-place		—	—	—	—	—	—	—	—	—	—
		—	2	—	3	(75)	(27)	874	(5)	—	772
At 31 December ^{g,h}											
Developed		—	108	—	—	1,130	507	9,324	10	—	11,079
Undeveloped		—	56	—	6	447	—	8,067	—	—	8,576
		—	164	—	6	1,577	507	17,391	10	—	19,656
Total subsidiaries and equity-accounted entities (BP share)											
At 1 January											
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
At 31 December											
Developed		493	108	6,330	—	3,323	1,670	9,324	3,677	2,256	27,181
Undeveloped		207	56	2,127	6	2,682	742	8,067	3,401	1,132	18,421
		700	164	8,458	6	6,004	2,412	17,391	7,078	3,389	45,601

^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 3,054 billion cubic feet of natural gas associated with Assets Held for Sale in the USA.

^d Includes 188 billion cubic feet of natural gas consumed in operations, 146 billion cubic feet in subsidiaries, 42 billion cubic feet in equity-accounted entities.

^e Includes 1,330 billion cubic feet of natural gas 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 1,433 billion cubic feet of natural gas in respect of the 9.72% non-controlling interest in Rosneft including 569 billion cubic feet held through BP's interests in Russia other than Rosneft.

^h Total proved gas reserves held as part of our equity interest in Rosneft is 14,705 billion cubic feet, comprising 28 billion cubic feet in Venezuela, 10 billion cubic feet in Vietnam, 171 billion cubic feet in Egypt and 14,495 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

	million barrels of oil equivalent ^c									
Total hydrocarbons ^{a, b}	2019									
	Europe		North America		South America	Africa	Asia	Australasia		Total
	UK	Rest of Europe	US ^{d, e}	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	(29)	—	(297)	(8)	(45)	39	—	153	(21)	(208)
Improved recovery	3	—	305	1	—	—	—	—	—	309
Purchases of reserves-in-place	—	—	—	—	—	—	—	10	—	10
Discoveries and extensions	—	—	36	—	31	—	—	63	—	130
Production ^{f, g}	(48)	—	(335)	(9)	(131)	(137)	—	(191)	(57)	(908)
Sales of reserves-in-place	—	—	(95)	—	—	(49)	—	—	—	(144)
	(74)	—	(386)	(16)	(146)	(147)	—	35	(78)	(813)
At 31 December ^h										
Developed	300	—	2,384	40	387	369	—	1,707	419	5,604
Undeveloped	241	—	1,459	179	411	171	—	1,111	199	3,771
	540	—	3,842	218	798	540	—	2,818	618	9,375
Equity-accounted entities (BP share)ⁱ										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	4	—	1	(31)	13	282	—	—	269
Improved recovery	—	7	—	—	—	—	—	—	—	7
Purchases of reserves-in-place	—	—	—	—	—	—	7	—	—	7
Discoveries and extensions	—	—	—	—	64	—	369	—	—	434
Production ^f	—	(17)	—	—	(47)	(13)	(424)	(1)	—	(503)
Sales of reserves-in-place	—	—	—	—	—	—	(6)	—	—	(6)
	—	(6)	—	1	(14)	—	229	(1)	—	208
At 31 December ^k										
Developed	—	139	—	—	488	100	4,856	2	—	5,585
Undeveloped	—	47	—	21	334	—	3,978	—	—	4,381
	—	186	—	21	822	100	8,834	2	—	9,965
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	300	139	2,384	40	875	469	4,856	1,708	419	11,189
Undeveloped	241	47	1,459	199	746	171	3,978	1,112	199	8,152
	540	186	3,842	239	1,621	640	8,834	2,820	618	19,341

^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 4.5 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 Includes 982 million barrels of oil equivalent associated with Assets Held for Sale in the USA.

^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 32 million barrels of oil equivalent of natural gas consumed in operations, 25 million barrels of oil equivalent in subsidiaries, 7 million barrels of oil equivalent in equity-accounted entities.

^h Includes 240 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 603 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 124 mboe held through BP's interests in Russia other than Rosneft.

^k Total proved reserves held as part of our equity interest in Rosneft is 8,281 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Iraq and Canada, 40 million barrels of oil equivalent in Venezuela, 2 million barrels of oil equivalent in Vietnam, 30 million barrels of oil equivalent in Egypt and 8,208 million barrels of oil equivalent in Russia.

Movements in estimated net proved reserves – continued

Crude oil ^{a, b}	million barrels									
	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	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	(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 ^{d, 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
										2018
										Total
Europe		North America		South America	Africa	Asia		Australasia		
UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia			
Natural gas liquids^{a,b}										
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.

^g 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	—	—	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 mmbbl 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

Natural gas ^{a,b}	billion cubic feet									
	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

Total hydrocarbons ^{a, b}	million barrels of oil equivalent ^c									
	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										
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 mmbbl 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	(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 ^{d,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.

Movements in estimated net proved reserves – continued

Natural gas liquids ^{a, b}	million barrels									
										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 mmbbl held through BP's equity accounted interest in Taas-Yuryakh Neftegazodobycha.

^h Total proved liquid reserves held as part of our equity interest in Rosneft is 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}	billion cubic feet									
	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	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}	million barrels of oil equivalent ^c									
	2017									
	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	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 mmbc 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.

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									
	2019									
	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	28,600	—	135,900	7,400	11,500	21,200	—	135,800	24,000	364,400
Future production cost ^b	13,700	—	59,200	3,400	5,700	6,700	—	53,200	6,100	148,000
Future development cost ^b	1,700	—	16,400	1,200	2,000	1,300	—	16,700	2,700	42,000
Future taxation ^c	5,200	—	8,700	200	1,300	3,300	—	46,000	5,300	70,000
Future net cash flows	8,000	—	51,600	2,600	2,500	9,900	—	19,900	9,900	104,400
10% annual discount ^d	2,700	—	23,100	1,400	600	2,300	—	7,200	4,400	41,700
Standardized measure of discounted future net cash flows ^{e,f}	5,300	—	28,500	1,200	1,900	7,600	—	12,700	5,500	62,700
Equity-accounted entities (BP share)^g										
Future cash inflows ^a	—	10,300	—	—	36,800	—	322,000	—	—	369,100
Future production cost ^b	—	3,500	—	—	14,900	—	222,600	—	—	241,000
Future development cost ^b	—	700	—	—	3,900	—	21,800	—	—	26,400
Future taxation ^c	—	4,700	—	—	4,100	—	13,300	—	—	22,100
Future net cash flows	—	1,400	—	—	13,900	—	64,300	—	—	79,600
10% annual discount ^d	—	400	—	—	8,200	—	37,100	—	—	45,700
Standardized measure of discounted future net cash flows ^{h,i}	—	1,000	—	—	5,700	—	27,200	—	—	33,900
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows ^j	5,300	1,000	28,500	1,200	7,600	7,600	27,200	12,700	5,500	96,600

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

	\$ million		
	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(27,400)	(8,400)	(35,800)
Development costs for the current year as estimated in previous year	9,200	4,100	13,300
Extensions, discoveries and improved recovery, less related costs	3,800	2,600	6,400
Net changes in prices and production cost	(28,100)	(8,200)	(36,300)
Revisions of previous reserves estimates	300	1,100	1,400
Net change in taxation	16,600	2,400	19,000
Future development costs	(1,500)	(4,300)	(5,800)
Net change in purchase and sales of reserves-in-place	(1,400)	—	(1,400)
Addition of 10% annual discount	8,300	4,100	12,400
Total change in the standardized measure during the year ^k	(20,200)	(6,600)	(26,800)

^a The marker prices used were Brent \$62.74/bbl, Henry Hub \$2.58/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 \$600 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 \$2,100 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 Includes future net cash flows for assets held for sale at 31 December 2019.

^k 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									
	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	—	238,400	—	—	258,700
Future development cost ^b	—	800	—	—	3,600	—	19,300	—	—	23,700
Future taxation ^c	—	5,900	—	—	4,400	—	17,700	—	—	28,000
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	3,300	9,100
Net changes in prices and production cost	41,000	13,100	54,100
Revisions of previous reserves estimates	(2,100)	2,000	(100)
Net change in taxation	(17,000)	(4,600)	(21,600)
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. 2018 comparative for Russia equity-accounted entity future production cost has been restated from \$232,100 million to maintain consistency with 2019 presentation.

^c Taxation is computed with reference to appropriate year-end statutory corporate income tax rates. 2018 comparative for Russia equity-accounted entity future taxation has been restated from \$24,000 million to maintain consistency with 2019 presentation.

^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 yearⁱ	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 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 2019, 2018 and 2017.

Production for the year^{a, b}

	Europe		North America	South America	Africa	Asia	Australasia	Total		
	UK	Rest of Europe	US	Rest of North America		Russia ^c	Rest of Asia			
Subsidiaries^d										
Crude oil ^e	thousand barrels per day									
2019	100	—	400	24	7	156	—	343	17	1,046
2018	101	—	385	24	7	204	—	313	17	1,051
2017	80	—	370	20	12	241	—	325	17	1,064
Natural gas liquids	thousand barrels per day									
2019	3	—	81	—	9	8	—	—	2	104
2018	5	—	60	—	9	11	—	—	2	88
2017	6	—	56	—	10	10	—	—	2	85
Natural gas ^f	million cubic feet per day									
2019	129	—	2,358	2	1,977	1,138	—	976	786	7,366
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
Equity-accounted entities (BP share)										
Crude oil ^e	thousand barrels per day									
2019	—	35	—	—	56	1	955	—	—	1,047
2018	—	34	—	—	55	1	933	16	—	1,040
2017	—	31	—	—	63	1	905	99	—	1,099
Natural gas liquids	thousand barrels per day									
2019	—	2	—	—	1	8	3	—	—	14
2018	—	2	—	—	—	6	4	—	—	12
2017	—	2	—	—	—	6	4	—	—	12
Natural gas ^f	million cubic feet per day									
2019	—	56	—	—	314	87	1,279	—	—	1,736
2018	—	59	—	—	335	80	1,286	—	—	1,760
2017	—	53	—	—	418	77	1,308	—	—	1,855

^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 All of the oil and liquid production from Canada is bitumen.

^e Crude oil includes condensate.

^f Natural gas production excludes gas consumed in operations.

Operational and statistical information – continued

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 2019. 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 ^a	
	UK	Rest of Europe	US	Rest of North America			Russia ^a	Rest of Asia		
Number of productive wells at 31 December 2019										
Oil wells ^c										
– gross	117	80	2,775	177	5,526	290	66,696	2,067	12	77,740
– net	70	24	1,152	48	2,528	65	13,278	477	2	17,644
Gas wells ^d										
– gross	36	1	18,552	238	1,119	220	447	129	78	20,820
– net	7	–	8,811	118	401	91	92	60	16	9,596
Oil and natural gas acreage at 31 December 2019										
										thousands of acres
Developed										
– gross	75	81	6,232	143	1,354	823	7,709	1,322	173	17,912
– net	44	24	3,658	62	361	287	1,377	292	41	6,146
Undeveloped ^e										
– gross	2,851	150	5,311	14,953	23,892	51,105	439,848	9,793	4,022	551,925
– net	1,594	45	3,749	7,890	8,456	33,683	84,689	2,430	1,889	144,425

^a Based on information received from Rosneft as at 31 December 2019.

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

^c Includes approximately 6,916 gross (1,314 net) multiple completion wells (more than one formation producing into the same well bore).

^d Includes approximately 2,618 gross (1,265 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		
2019										
Exploratory										
Productive	–	0.2	0.8	0.8	3.5	2.3	11.6	5.2	–	24.4
Dry	1.0	0.3	1.6	0.5	1.1	0.3	0.5	0.4	0.2	5.9
Development										
Productive	1.7	2.4	193.0	0.2	110.7	6.0	230.8	49.6	0.4	594.8
Dry	–	0.3	10.0	–	0.6	–	–	1.0	–	11.9
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

^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 2019. 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 2019										
Exploratory										
Gross	—	—	8.0	—	2.0	4.0	—	5.0	—	19.0
Net	—	—	4.9	—	0.5	1.6	—	0.5	—	7.5
Development										
Gross	6.0	3.6	213.0	6.0	13.0	26.0	—	216.0	2.0	485.6
Net	2.0	1.1	140.0	3.0	4.1	14.5	—	29.1	0.8	194.6

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

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

Company balance sheet

At 31 December		\$ million	
	Note	2019	2018
Non-current assets			
Investments	2	166,256	166,271
Receivables	3	2,771	2,600
Defined benefit pension plan surpluses	4	6,588	5,473
		175,615	174,344
Current assets			
Receivables	3	135	151
Cash and cash equivalents		—	13
		135	164
Total assets		175,750	174,508
Current liabilities			
Payables	5	18,007	14,665
Non-current liabilities			
Payables	5	31,927	31,800
Deferred tax liabilities	6	2,293	1,907
Defined benefit pension plan deficits	4	202	184
		34,422	33,891
Total liabilities		52,429	48,556
Net assets		123,321	125,952
Capital and reserves^a			
Profit and loss account			
Brought forward		96,430	101,078
Profit for the year		4,470	1,931
Other movements		(8,829)	(6,579)
		92,071	96,430
Called-up share capital	7	5,404	5,402
Share premium account		12,417	12,305
Other capital and reserves		13,429	11,815
		123,321	125,952

^a See Statement of changes in equity on page 261 for further information.

The financial statements on pages 260-296 were approved and signed by the group chief executive on 18 March 2020 having been duly authorized to do so by the board of directors:

B Looney Chief executive officer

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 2019	5,402	12,305	1,439	26,509	(15,767)	(366)	96,430	125,952
Profit for the year	—	—	—	—	—	—	4,470	4,470
Other comprehensive income	—	—	—	—	—	200	401	601
Total comprehensive income	—	—	—	—	—	200	4,871	5,071
Dividends	52	(52)	—	—	—	—	(6,929)	(6,929)
Repurchases of ordinary share capital	(59)	—	59	—	—	—	(1,511)	(1,511)
Share-based payments, net of tax	9	164	—	—	1,355	—	(790)	738
At 31 December 2019	5,404	12,417	1,498	26,509	(14,412)	(166)	92,071	123,321
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

^a See Note 8 for further information.

The parent company financial statements of BP p.l.c. on pages 260-296 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Notes on financial statements

1. Significant accounting policies, judgements, estimates and assumptions

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

The financial statements of BP p.l.c. for the year ended 31 December 2019 were approved and signed by the chief executive officer on 18 March 2020 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 in paragraph 38 of IAS 1 'Presentation of Financial Statements' to present comparative information in respect of paragraph 79(a)(iv) of IAS 1.
- (d) the requirements of IAS 7 'Statement of Cash Flows';
- (e) 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;
- (f) the requirements of paragraphs 17 and 18A of IAS 24 'Related Party Disclosures';
- (g) 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; and
- (h) 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 260-296 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 260-296 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 rights to receive cash flows have been transferred to a third party along with substantially all of the risks and rewards or control of the 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.

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 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.

Impact of new International Financial Reporting Standards

The company adopted IFRS 16 'Leases', which replaced IAS 17 'Leases' and IFRIC 4 'Determining whether an arrangement contains a lease', with effect from 1 January 2019. The adoption of IFRS 16 has had no material impact on the company's financial statements. There are no other new or amended standards or interpretations adopted during the year that have a significant impact on the financial statements.

2. Investments

	\$ million		
	Subsidiaries	Associates	
	Shares	Shares	Total
Cost			
At 1 January 2019	166,302	2	166,304
Additions	—	—	—
Disposals	(15)	—	(15)
At 31 December 2019	166,287	2	166,289
Amounts provided			
At 1 January 2019	33	—	33
At 31 December 2019	33	—	33
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
At 31 December 2019	166,254	2	166,256
At 31 December 2018	166,269	2	166,271

The more important subsidiaries of the company at 31 December 2019 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 2019 was \$76,152 million (2018 \$76,152 million).

3. Receivables

	\$ million			
	2019		2018	
	Current	Non-current	Current	Non-current
Amounts receivable from subsidiaries ^a	134	2,771	148	2,600
Amounts receivable from associates	1	—	4	—
Other receivables	—	—	(1)	—
	135	2,771	151	2,600

^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 2019 the aggregate level of contributions was \$236 million (2018 \$490 million). The aggregate level of contributions in 2020 is expected to be approximately \$255 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.

The parent company financial statements of BP p.l.c. on pages 260-296 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

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 \$1,276 million at 31 December 2019, 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 2019. 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		
	2019	2018
	%	
Discount rate for pension plan liabilities	2.1	2.9
Rate of increase in salaries	3.4	3.8
Rate of increase for pensions in payment	2.7	3.0
Rate of increase in deferred pensions	2.7	3.0
Inflation for pension plan liabilities	2.7	3.1

Financial assumptions used to determine benefit expense		
	2019	2018
	%	
Discount rate for pension plan service costs	3.0	2.6
Discount rate for pension plan other finance expense	2.9	2.5
Inflation for pension plan service costs	3.1	3.1

The discount rate assumption is based on third-party AA corporate bond indices and we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumption is based on the difference between the yields on index-linked and fixed-interest long-term government bonds. The inflation assumption is used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions.

The assumption for the rate of increase in salaries is based on our inflation assumption plus an allowance for expected long-term real salary growth. This 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		
	2019	2018
	Years	
Life expectancy at age 60 for a male currently aged 60	27.3	27.4
Life expectancy at age 60 for a male currently aged 40	28.9	28.9
Life expectancy at age 60 for a female currently aged 60	28.7	28.8
Life expectancy at age 60 for a female currently aged 40	30.5	30.6

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 2019, the plan switched 2% from equities to bonds (2018 12.5%).

The company's asset allocation policy for the primary plan is as follows:

Asset category		
	2019	2018
	%	
Total equity (including private equity)	28	
Bonds/cash (including LDI)	65	
Property/real estate	7	

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2019 were \$4,804 million (2018 \$4,197 million) of government-issued nominal bonds and \$19,462 million (2018 \$17,491 million) of index-linked bonds.

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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 268.

	\$ million	
	2019	2018
Fair value of pension plan assets		
Listed equities – developed markets	6,285	5,191
– emerging markets	1,096	950
Private equity ^a	2,675	2,792
Government issued nominal bonds ^b	4,884	4,263
Government issued index-linked bonds ^b	19,462	17,491
Corporate bonds ^b	6,132	4,606
Property ^c	2,507	2,311
Cash	426	376
Other	98	116
Debt (repurchase agreements) used to fund liability driven investments	(7,436)	(6,011)
	36,129	32,085

^a Private equity is valued at fair value based on the most recent third-party net asset, revenue or earnings based valuations that generally result in the use of significant unobservable inputs.

^b Bonds held are denominated in sterling and valued using quoted prices in active markets.

^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	
	2019	2018
Analysis of the amount charged to profit or loss		
Current service cost ^a	227	295
Past service cost ^b	2	15
Operating charge relating to defined benefit plans	229	310
Payments to defined contribution plan	42	38
Total operating charge	271	348
Interest income on plan assets ^c	(909)	(868)
Interest on plan liabilities	756	773
Other finance (income)	(153)	(95)
Analysis of the amount recognized in other comprehensive income		
Actual asset return less interest income on pension plan assets	2,945	(722)
Change in financial assumptions underlying the present value of the plan liabilities	(2,292)	1,768
Change in demographic assumptions underlying the present value of plan liabilities	136	123
Experience gains and losses arising on the plan liabilities	(57)	520
Remeasurements recognized in other comprehensive income	732	1,689

^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

	\$ million	
	2019	2018
Movements in benefit obligation during the year		
Benefit obligation at 1 January	26,796	31,474
Exchange adjustments	941	(1,587)
Operating charge relating to defined benefit plans	229	310
Interest cost	756	773
Contributions by plan participants ^a	20	21
Benefit payments (funded plans) ^b	(1,207)	(1,780)
Benefit payments (unfunded plans) ^b	(5)	(4)
Remeasurements	2,213	(2,411)
Benefit obligation at 31 December	29,743	26,796
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	32,085	35,091
Exchange adjustments	1,141	(1,883)
Interest income on plan assets ^c	909	868
Contributions by plan participants ^a	20	21
Contributions by employers (funded plans)	236	490
Benefit payments (funded plans) ^b	(1,207)	(1,780)
Remeasurements ^c	2,945	(722)
Fair value of plan assets at 31 December ^{d,e}	36,129	32,085
Surplus at 31 December	6,386	5,289
Represented by		
Asset recognized	6,588	5,473
Liability recognized	(202)	(184)
	6,386	5,289
The surplus may be analysed between funded and unfunded plans as follows		
Funded	6,588	5,473
Unfunded	(202)	(184)
	6,386	5,289
The defined benefit obligation may be analysed between funded and unfunded plans as follows		
Funded	(29,541)	(26,612)
Unfunded	(202)	(184)
	(29,743)	(26,796)

^a Most of the contributions made by plan participants were made under salary sacrifice.

^b The benefit payments amount shown above comprises \$1,194 million benefits (2018 \$1,764 million) plus \$18 million (2018 \$20 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 \$35,811 million of assets held in the BP Pension Fund (2018 \$31,818 million) and \$251 million held in the BP Global Pension Trust (2018 \$203 million), as well as \$53 million representing the company's share of Merchant Navy Officers Pension Fund (2018 \$51 million) and \$14 million of Merchant Navy Ratings Pension Fund (2018 \$13 million).

^e The fair value of plan assets includes borrowings related to the LDI programme as described on page 266.

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 2019 for the company's plans would have had the effects shown in the table below. The effects shown for the expense in 2020 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 2020	(274)	227
Effect on pension obligation at 31 December 2019	(4,725)	6,359
Inflation rate ^b		
Effect on pension expense in 2020	171	(134)
Effect on pension obligation at 31 December 2019	4,711	(3,890)
Salary growth		
Effect on pension expense in 2020	42	(36)
Effect on pension obligation at 31 December 2019	604	(525)

^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 2020 pension expense by \$31 million and the pension obligation at 31 December 2019 by \$1,130 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 2019 are as follows:

	\$ million
Estimated future benefit payments	
2020	1,063
2021	1,076
2022	1,096
2023	1,136
2024	1,150
2025-2029	5,886
	Years
Weighted average duration	18.3

5. Payables

	2019		2018	
	Current	Non-current	Current	Non-current
Amounts payable to subsidiaries	17,916	31,894	14,559	31,765
Accruals and deferred income	21	—	31	—
Other payables	70	33	75	35
	18,007	31,927	14,665	31,800

Included in non-current amounts payable to subsidiaries is an interest-bearing payable of \$4,236 million (2018 \$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 (2018 \$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 \$5,031 million (2018 \$5,000 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.

	2019		2018	
Due within				
1 to 2 years		48		40
2 to 5 years		31,499		31,520
More than 5 years		380		240
		31,927		31,800

6. Taxation

	2019		2018	
Tax charge included in total comprehensive income				
Deferred tax				
Origination and reversal of temporary differences in the current year		389		570
This comprises:				
Taxable temporary differences relating to pensions		389		570
Deferred tax				
Deferred tax liability				
Pensions		2,293		1,907
Net deferred tax liability		2,293		1,907
Analysis of movements during the year				
At 1 January		1,907		1,337
Charge (credit) for the year in the income statement		55		59
Charge (credit) for the year in other comprehensive income		331		511
At 31 December		2,293		1,907

At 31 December 2019, deferred tax assets of \$467 million on other temporary differences, \$9 million relating to pensions, \$67 million relating to income losses and \$391 million relating to other deductible temporary differences (2018 \$258 million relating to other temporary differences, \$7 million relating to pensions, \$67 million relating to income losses and \$184 million relating to other deductible temporary differences) 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 unrecognized 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:

	2019		2018	
	Shares thousand	\$ million	Shares thousand	\$ million
Issued				
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	21,525,464	5,381	21,288,193	5,322
Issue of new shares for the scrip dividend programme	208,927	52	195,305	49
Issue of new shares for employee share-based payment plans	37,400	9	92,168	23
Repurchase of ordinary share capital	(235,951)	(59)	(50,202)	(13)
At 31 December	21,535,840	5,383	21,525,464	5,381
		5,404		5,402

^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 2019 the company repurchased 236 million ordinary shares at a cost of \$1,511 million, including transaction costs of \$8 million, as part of the share repurchase programme announced on 31 October 2017. All shares purchased were for cancellation. The repurchased shares represented 1.1% of ordinary share capital.

Treasury shares^a

	2019		2018	
	Shares thousand	Nominal value \$ million	Shares thousand	Nominal value \$ million
At 1 January	1,426,265	356	1,482,072	370
Purchases for settlement of employee share plans	1,118	—	757	—
Issue of new shares for employee share-based payment plans	37,400	9	92,168	23
Shares re-issued for employee share-based payment plans	(167,927)	(42)	(148,732)	(37)
At 31 December	1,296,856	323	1,426,265	356
Of which - shares held in treasury by BP	1,163,077	290	1,264,732	316
- shares held in ESOP trusts	133,707	33	161,518	40
- shares held by BP's US plan administrator ^b	72	—	15	—

^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 5.9% (2018 6.9%) of the called-up ordinary share capital of the company.

During 2019, the movement in shares held in treasury by BP represented less than 0.5% (2018 less than 1.0%) 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 (2018 \$24,107 million), the distribution of which is limited by statutory or other restrictions.

The financial statements for the year ended 31 December 2019 do not reflect the dividend announced on 4 February 2020 and paid in March 2020; this will be treated as an appropriation of profit in the year ended 31 December 2020.

9. Financial guarantees

The company has issued guarantees under which the maximum aggregate liabilities at 31 December 2019 were \$78,586 million (2018 \$77,965 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	
	2019	2018
Total expense recognized for equity-settled share-based payment transactions	433	429
Total (credit) expense recognized for cash-settled share-based payment transactions	(1)	(9)
Total expense recognized for share-based payment transactions	432	420
Closing balance of liability for cash-settled share-based payment transactions	17	27
Total intrinsic value for vested cash-settled share-based payments	16	23

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	
	2019	2018
Remuneration of directors		
Total for all directors		
Emoluments	9	8
Amounts awarded under incentive schemes ^a	20	16
Total	29	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. Further information is provided in the Directors' remuneration report on page 100.

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13. Employee costs and numbers

	\$ million	
Employee costs	2019	2018
Wages and salaries	468	491
Social security costs	84	74
Pension costs	63	80
	615	645

Average number of employees	2019	2018
Upstream	279	269
Downstream	1,142	1,151
Other businesses and corporate	2,300	2,344
	3,721	3,764

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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 2019 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
563916 Alberta Ltd. (99.90%) ^a	240- 4th 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 ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Goshen II Holdings LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Goshen II Wind Farm LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Power Services LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Wind PartsCo LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Air BP Albania SHA	Air BP Albania Sh.A., 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 ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Air BP Croatia d.o.o.	Savska cesta 32, Zagreb, Croatia
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	Drammensveien 167, Oslo, 0277, 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 ^c	17 Level, 717 Bourke Street, Docklands, Melbourne VIC 3008, 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 ^b	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 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 Environmental Services Company ^d	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 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 ID 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 ^e	188, Awolowo Road, S.W. Ikoyi, Lagos, Nigeria
Amoco Nigeria Oil Company Limited ^e	188, Awolowo Road, S.W. Ikoyi, Lagos, Nigeria
Amoco Nigeria Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Nigeria Petroleum Company Limited	188, Awolowo Road, S.W. Ikoyi, Lagos, Nigeria
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

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14. Related undertakings of the group – continued

Amoco Pipeline Holding Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Properties Incorporated	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Remediation Management Services Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, 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 ^f	801 Adlai Stevenson Drive, Springfield, IL, 62703, United States
Amprop, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, 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 Berchem Ouest, Luxembourg
Aral Tankstellen Services Sarl	Bâtiment B, 36route de Longwy, L-8080 Bertrange, Luxembourg
ARCO British International, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO British Limited, LLC ^b	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 Environmental Remediation, L.L.C. ^b	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 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 Mediterraneo Inversiones, S.L	Federico Garcia Lorca, 43, entreplanta, 04004, Almeria, Spain
ARCO Midcon LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Oil Company Nigeria Unlimited ^b	8/10, Broad Street, Lagos, Nigeria
ARCO Oman Inc.	Trident Corporate Services (Bahamas) Limited, Providence House, East Hill Street, P.O.Box N-3944, Nassau, Bahamas, Bahamas
ARCO Resources Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
ARCO Trinidad Exploration and Production Company Limited	2 Bayside Executive Park, West Bay, Nassau, Bahamas
ARCO Unimar Holdings LLC ^b	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.	Cl Velázquez 18 4ªPlanta 28001 , Madrid, Spain
Aspac Lubricants (Malaysia) Sdn. Bhd. (63.03%)	Level 9, 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 ^d	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Autino Holdings Limited (88.85%) ^a	Abbey Gardens, 7th Floor, 4 Abbey Street, Reading, RG1 3BA, United Kingdom
Autino Limited (88.85%)	Abbey Gardens, 7th Floor, 4 Abbey Street, Reading, RG1 3BA, United Kingdom
Auwahi Wind Energy Holdings LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
B2Mobility GmbH	Wittener Straße 45, 44789 Bochum, Germany
Bahia de Bizkaia Electricidad, S.L. (75.00%)	Atraque Punta Lucero, Explanada Punta Ceballos s/n, Zierbena (Vizcaya), Spain
Baltimore Ennis Land Company, Inc.	4400 Easton Commons Way , Suite 125, Columbus OH 43219, United States
BASS Management Pty Ltd (61.00%)	Level 17, 717 Bourke Street, Docklands VIC, Australia
Black Lake Pipe Line Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP- Castrol (Thailand) Limited (57.59%) ^h	23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South 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 ^f	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (China) Holdings Limited ^b	Room 2101, 21F Youyou International Plaza, 76 Pujian Road, Pudong, Shanghai Pilot Free Trade Zone, PRC
BP (China) Industrial Lubricants Limited ^b	No.9 Bin Jiang South Road, Petrochemical Industrial Park, Taicang Gangkou Development Zone, Jiangsu Province, China
BP (Gibraltar) Limited ^f	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (GTA Mauritania) Finance Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (GTA Senegal) Finance Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (Guangzhou) Advanced Mobility Limited ^b	Room 1218, Building 3, No. 6 Hanxing San jie, Zhongcun Street, Panyu District, Guangzhou, Guangdong Province , China
BP (Hunan) Petroleum Company Limited ^b	Room 1001, 10th Floor, Building A2, Xiangjiang Times Business Square, No.179 Xiandao Road, Yuelu District, Changsha, Hunan, China
BP (Indian Agencies) Limited ^f	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom

The parent company financial statements of BP p.l.c. on pages 260-296 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 (Shandong) Petroleum Co., Ltd ^b	Room 1-2201, Sijian Meilin Mansion, No. 48-15 Wuyingshan Middle Road, Tianqiao District, Ji'nan, Shandong, China
BP (Shanghai) Trading Limited ^b	Room 2105, No. 28 Maji Road, Donghua Financial Building, China (Shanghai) Pilot Free Trade, Shanghai, 200131, 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 ^d	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Africa Oil Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Akaryakit Ortakligi (70.00%) ^f	Degirmen yolu cad. No:28 , Asia OfisPark K:3 İcerenkoy-Atasehir, Istanbul, 34752, Turkey
BP Alaska LNG LLC ^b	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 Alternative Energy Trinidad and Tobago Limited	5-5A Queen's Park West, Port-of-Spain, Trinidad and Tobago
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 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 Andaman II Ltd	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, 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 ^b	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, Hong Kong
BP Asia Pacific (Malaysia) Sdn. Bhd.	Level 9, 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 ^d	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 ^a	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 ^k	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, I/SKøbenhavns Lufthavn 1, 2770 Kastrup, Denmark
BP Benevolent Fund Trustees Limited ^d	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. (96.53%)	Avenida das Nações Unidas, 12399, 4fl, Sao Paulo, Brazil
BP Bioenergia Campina Verde Ltda. (96.53%)	Rua Principal, Fazenda Recanto, Zona Rural, Caixa Postal 01, Ituiutaba, Minas Gerais, 38.300-898, Brazil
BP Bioenergia Ituiutaba Ltda. (96.53%)	Fazenda Recanto, Zona Rural, CEP 38.300-898, Ituiutaba, Minas Gerais, Brazil
BP Bioenergia Itumbiara S.A. (96.53%)	Estrada Municipal Itumbiara / Chacoeira Dourada, Fazenda Jandaia, Gleba B, Itumbiara, Goiás, 75516-126, Brazil
BP Bioenergia Tropical S.A. (97.46%)	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 ^b	5615 Corporate Blvd., Suite 400B, Baton Rouge LA 70808, United States
BP Biofuels North America LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Biofuels Trading Comércio, Importação e Exportação Ltda. (96.53%)	Avenida das Nações Unidas, 12399, 4fl, Sao Paulo, Brazil
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. ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Bulwer Island Pty Ltd ^d	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Business Service Centre Asia Sdn Bhd	Level 9, Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia

The parent company financial statements of BP p.l.c. on pages 260-296 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 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, Attention: Lawrence J. Stordy, 900, 1959 Upper Water Street, Halifax NS B3J 3N2, Canada
BP Canada Energy Group ULC	Stewart McKelvey, Attention: Lawrence J. Stordy, 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 ^d	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%)	Level 9, Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia
BP Central Pipelines LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Chembel	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 China Exploration and Production Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP CIV Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Comercializadora de Energia Ltda.	Avenida das Nações Unidas, 12399, rooms 62,63 and 64 size B, 6th floor, Landmark Building, São Paulo, 04578-000, 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. ^m	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 ^o	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 (54.37%) ^f	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Developments Australia Pty. Ltd.	Level 15, 240 St Georges Terrace, Perth WA 6000, Australia
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 ⁿ	Avenida de Barajas 30, Madrid, Madrid, Spain
BP Estaciones y Servicios Energéticos, Sociedad Anónima de Capital Variable ^e	Avenida Santa Fe 505, Piso 10, Distrito Federal , MEXICO C.P. 0534, Mexico
BP Europa SE ^o	Überseeallee 1, 20457, Hamburg, Hamburg, Germany
BP Exploracion de Venezuela S.A.	Av. Francisco de Miranda, con primera avenida de Los Palos , Grandes, Edif Cavendes, piso 9, ofi 903, Los Palos Grandes, Chacao / Caracas, Caracas / Miranda, 1060, Venezuela, Bolivarian Republic of
BP Exploration & Production Inc. ^d	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
BP Exploration (Canada) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom

The parent company financial statements of BP p.l.c. on pages 260-296 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 (Caspian Sea) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (D230) 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	PricewaterhouseCoopers (Bahamas) 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 (Gambia) Limited	3 Kairaba Avenue, 3rd Floor Centenary, Serekunda West, Kanifing Municipality, Gambia
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	1, Oyinka Abayomi Drive, Ikoyi, Lagos, Nigeria
BP Exploration (Psi) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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 (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 Argentina Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Australia Pty Ltd	Level 15, 240 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	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. ^c	Av. Santa Fe No. 505 Piso 10, Col. Cruz Manca Santa Fe, Deleg. CuajimalpaC.P., 05349 México D.F., Mexico
BP Exploration North Africa Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Operating Company Limited	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 Exploration Peru 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 ^b	251 East Ohio Street, Suite 500, Indianapolis IN 46204, United States
BP France	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
BP Fuels & Lubricants AS	Drammensveien 167, Oslo, 0277, Norway
BP Fuels Deutschland GmbH	Wittener Straße 45, 44789 Bochum, Germany
BP Gas & Power Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Gas Europe, S.A.U.	Avenida de la Transición Española 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 ^b	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 ^d	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 ^b	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%) ^b	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 (81.18%) ^b	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 ^d	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 ^d	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, Hong Kong
BP India Private Limited (88.65%)	Technopolis Knowledge Park, Mahakali Caves Road, Andheri (East), Mumbai 400093, India
BP Indonesia Investment Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP International Limited ^d	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP International Services Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States

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14. Related undertakings of the group – continued

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.	15th Fl. Roppongi Hills Mori Tower, 10-1 Roppongi 6-chome, Minato-ku, Tokyo106-6115, Japan
BP Korea Limited	2nd Floor, 306, Banpo-daero, Seocho-gu, Seoul 06509, Republic of Korea
BP Kuwait Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Latin America LLC ^b	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	Washington House, 4th Floor, 16 Church Street, Hamilton HM 11 , 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%)	Level 9, 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 ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
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 ^d	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 ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Midstream Partners Holdings LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Midstream Partners LP (54.37%) ^a	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Midwest Product Pipelines Holdings LLC ^b	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 ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Offshore Response Company LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Oil (Thailand) Limited (90.40%) ^f	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.	26A Apostolopoulou, Halandri, Athens, Attica, 152 31, 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 Senegal S.A.	Route de Ouakam x Corniche Ouest, Immeuble Alphadio Barry, Dakar, Senegal
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 One Pipeline Company LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
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 Escrow Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pension Trustees Limited ^d	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pensions (Overseas) Limited ^d	Albert House, South Esplanade, St. Peter Port, GY1 1AW, Guernsey
BP Pensions Limited ^d	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom

The parent company financial statements of BP p.l.c. on pages 260-296 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 Petrochemicals India Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Petroleo y Gas, S.A.	Av. Francisco de Miranda, con primera avenida de Los Palos , Grandes, Edif Cavendes, piso 9, ofi 903, Los Palos Grandes, Chacao / Caracas, Caracas / Miranda, 1060, Venezuela, Bolivarian Republic of
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
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.	The Corporation Trust Incorporated, 351 West Camden Street, Baltimore MD 21201, United States
BP Properties Limited ^d	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 (54.37%) ^f	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 ^b	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 ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Solar Espana, S.A. Unipersonal ^f	Avenida de la Transición Española 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 Southern Africa Proprietary Limited (75.00%)	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, 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 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 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%) ^b	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 ^d	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Two Pipeline Company LLC (54.37%) ^f	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP UK Retained Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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 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%) ^b	Da Ping Harbour, Lin Gang Industrial Zone, Zhuhai City, Guangdong Province, China
BP+Amoco International Limited ^d	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%) ^b	153 Neftchilar Avenue, Baku, AZ1010, Azerbaijan
BPNE International B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BPRY Caribbean Ventures LLC (70.00%) ^b	RL&F Service Corp, 920 North King Street, 2nd Floor, Wilmington DE 19801, United States
BPX (Eagle Ford) Gathering LLC (75.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX (Karnes) Gathering LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX (KCS Resources) LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States

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14. Related undertakings of the group – continued

BPX (Permian) Gathering LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX (WSF Operating) Inc.	5615 Corporate Blvd., Suite 400B, Baton Rouge LA 70808, United States
BPX Energy Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX Midstream LLC ^b	The Corporation Company, 1833 South Morgan Road, Oklahoma City OK 73128, United States
BPX Operating Company	350 North St. Paul Street, Suite 2900, Dallas, Texas 75201, United States
BPX Production Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX Properties (GP) LLC ^b	CT Corporation System, 1021 Main Street, Suite 1150, Houston, Texas 77002, United States
BPX Properties (LP) LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX Properties (NA) LP ^f	1999 Bryan St., STE 900, Dallas TX 75201, 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%) ^s	5-7 Alexandra Road, Hemel Hempstead, Herts., 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 ^f	Level 17, 717 Bourke Street, Docklands VIC, Australia
Burmah Castrol Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Burmah Castrol PLC ^f	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
Burmah Castrol South Africa (Pty) Limited ^f	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, South Africa
Burmah Chile SpA	José Musalen Saffie, Huerfanos N° 770 Of. 301, Santiago, Chile
BXL Plastics Limited ^f	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Cadman DBP Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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, Hong Kong
Castrol (Ireland) Limited	One Spencer Dock, North Wall Quay, Dublin 1, Ireland
Castrol (Shanghai) Management Co., Ltd ^b	Floor 3, Building 5, 255 Guiqiao Road, Shanghai Pilot Free Trade Zone, China
Castrol (Shenzhen) Company Limited ^b	No.1120 Mawan Road, Nanshan District, Shenzhen, China
Castrol (Tianjin) Lubricants Co., Ltd ^b	South of NanGang Industrial Area, and East of Hai Gang Road, Tianjin Economic Development Area, Tianjin, China, 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 ^b	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%) ^b	9th Floor, 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 Ltda.	Calle 81, No 11 - 42, Oficina 901, Torre Sur, Bogota, Colombia
Castrol Del Peru S.A. (99.49%)	Av. Camino Real, 111 Torre B Oficina, 603 San Isidro, Lima, Peru
Castrol Egypt Lubricants S.A.E. (51.00%)	First floor of building located at Plot 28- the first Sector, City Center, New Cairo, Cairo, Egypt
Castrol India Limited (51.00%)	Technopolis Knowledge Park, Mahakali Caves Road, Andheri (East), Mumbai 400093, 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. ^c	Av. Santa Fe No. 505 Piso 10, Col. Cruz Manca Santa Fe, Deleg. Cuajimalpa C.P., 05349 México D.F., Mexico
Castrol Namibia (Pty) Limited	24 Orban Street, Klein Windhoek, Windhoek, Namibia
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
Castrol Philippines, Inc.	32/F LKG Tower, Ayala Avenue, Makati City, 6801, Philippines
Castrol Servicos Ltda.	Avenida Tamboré, 448, Barueri, Sao Paulo, Brazil
Castrol Ukraine LLC ^b	2A Kostiantynivska 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 ^d	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.	Avenida Eugenio Mendoza / San Felipe Edificio Centro Letonia, Torre Ing-Bank, Piso 12, Oficina 124-B, La Castellana, Caracas, 1060, Venezuela, Bolivarian Republic of
Conti Cross Keys Inn, Inc.	Easton and Swamp Roads, Buckinham Township, Bucks County, Pennsylvania, United States
Coro Trading NZ Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand

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14. Related undertakings of the group – continued

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	Timmerhellstr. 28, 45478, Mülheim/Ruhr, Germany
Dome Beaufort Petroleum Limited	240- 4th Avenue SW, Calgary AB T2P 4H4, Canada
Dome Wallis (1980) Limited Partnership (92.50%) ^f	240- 4th Avenue SW, Calgary AB T2P 4H4, Canada
Dradnats, Inc.	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Dualez 16, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
ECM Markets SA (Pty) Ltd (75.00%)	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, South Africa
Elektromotive Limited	500, Capability Green, Luton, LU1 3LS, United Kingdom
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 ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Estacion de Servicio Alto Campoo, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Estacion de Servicio Ganzo 10, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Estacion de Servicio Reocin 9, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Estacion de Servicio Santillana II, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Estacion de Servicio Sardinero, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Estonian Aviation Fuelling Services (50.00%)	Harju maakond, Lasnamäe linnaosa, Väike-Sõjamäe tn 12a, Tallinn, 11415, Estonia
Europa Oil NZ Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
Exomet, Inc.	4400 Easton Commons Way, Suite 125, Columbus OH 43219, 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 ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Flat Ridge Wind Energy, LLC ^b	112 SW 7th Street, Suite 3C, Topeka, Kansas, 66603
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 ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge I Land Investments LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge II Holdings LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge III Wind Farm LLC ^b	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 ^w	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
FWK Holdings (2017) LTD ^w	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Gardena Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Gelsenkirchen Raffinerie Netz GmbH	Alexander-von-Humboldt-Straße 1, Gelsenkirchen, 45896, Germany
GOAM 1 C.I.S. A. S	Callé 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 ^b	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
IGI Resources, Inc.	921 S. Orchard St. Ste G, Boise ID 83705, 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
Iraq Petroleum Company Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Jupiter Insurance Limited	Albert House, South Esplanade, St. Peter Port, GY1 1AW, Guernsey
Ken-Chas Reserve Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Kenilworth Oil Company Limited ^d	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 ^b	Novinskiy blvd.8, 17th floor, premises 11, 121099, Moscow, Russian Federation
Limited liability company Setra Lubricants ^b	2 Paveletskaya sq, Building1, 115054 Moscow, Russia
Lubricants UK Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Lytt Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom

The parent company financial statements of BP p.l.c. on pages 260-296 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

Manormaker (Nominee No. 1) Limited (99.90%)	11 Black Horse Lane, Ipswich, Suffolk, IP1 2EF, United Kingdom
Manormaker (Nominee No. 2) Limited (99.90%)	11 Black Horse Lane, Ipswich, Suffolk, IP1 2EF, United Kingdom
Manormaker GP Limited (99.90%)	11 Black Horse Lane, Ipswich, Suffolk, IP1 2EF, United Kingdom
Mardi Gas Transportation System Company LLC (70.34%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Markoil, S.A. Unipersonal	Avenida de la Transición Española 30, Parque Empresarial Omega, Edificio D. 28108 Alcobendas, Madrid, Spain
Masana Petroleum Solutions (Pty) Ltd (37.88%)	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, South Africa
Mayaro Initiative for Private Enterprise Development (70.00%)	5-5A Queen's Park West, Port-of-Spain, Trinidad and Tobago
Mehoopany Holdings LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Mes Tecnología En Servicios Y Energía, S.A. De C.V. ^c	Av. Santa Fe No. 505 Piso 10, Col. Cruz Manca Santa Fe, Deleg. Cuajimalpa C.P., 05349 México D.F., Mexico
Minza Pty. Ltd.	Level 17, 717 Bourke Street, Docklands VIC, Australia
Mountain City Remediation, LLC ^b	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
North America Funding Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
OMD87, Inc.	111 Eighth Avenue, New York, New York, 10011
Omega Oil Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
OnSight Analytics Solutions India Private Ltd. (74.50%)	Office No. 306, Regus Business Center , 3rd Floor, Abbusali St, Saligramam, Chennai, Tamil Nadu, 600093, India
OOO BP STL ^b	Novinskiy blvd.8, 18th floor, office 14, 121099, Moscow, Russian Federation
Orion Delaware Moun'ain Wind Farm LP ^b	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Orion Energy Holdings, LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Orion Energy L.L.C. ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Orion Post Land Investments, LLC ^b	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Oyambre 1, S.L.	Avenida de la Transición Española 30, Alcobendas, 28108, Madrid, Spain
Pacroy (Thailand) Co., Ltd. (39.50%)	23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South 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, 1ª Planta, 28760 Tres Cantos, Madrid, Spain
Phoenix Petroleum Services, Limited Liability Company	Royal Tulip Al Rasheed Hotel, Baghdad Tower, PO Box 8070, Baghdad, Iraq
Pozuelo 4, S.L.	Avenida de la Transición Española 30, Alcobendas, 28108, Madrid, Spain
PRODUITS METALLURGIE DOITTAU	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
Prospect International, C.A. (In liquidation)	Avenida Eugenio Mendoza / San Felipe Edificio Centro Letonia, Torre Ing-Bank, Piso 12, Oficina 124-B, La Castellana, Caracas, 1060, Venezuela, Bolivarian Republic of
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 9th Floor, Jl. Let. Jenderal TB. Simatupang Kav. 88, Jakarta 12520, Indonesia
PT Castrol Manufacturing Indonesia (68.30%)	JL. Raya, Merak KM 117, DS Gerem, Gerem Grogol, Cilegon, Banten, Indonesia
PT Jasatama Petroindo ^c	Perkantoran Hijau Arkadia, Tower B 8th Floor, Jl. Let. Jenderal TB. Simatupang Kav. 88, Jakarta 12520, Indonesia
Puente Arce 4, S.L.	Avenida de la Transición Española 30, Alcobendas, 28108, Madrid, Spain
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
Rio Corvo 2, S.L.	Avenida de la Transición Española 30, Alcobendas, 28108, Madrid, Spain
Rolling Thunder I Power Partners, LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Romax Insight Korea Ltd. (74.50%)	504 Smart Building, 213-3 Cheomdan-ro, Jeju-si, 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)	Alexander-von-Humboldt-Straße 1, Gelsenkirchen, 45896, Germany
Rusdene GSS Limited ^{dy}	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Saturn Insurance Inc.	400 Cornerstone Drive, Suite 240, Williston VT 05495, United States
Sherbino I Holdings LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Sherbino Mesa I Land Investments LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Sociedade de Promocao Imobiliaria Quinta do Loureiro, SA	Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal
Société de Gestion de Dépôts d'Hydrocarbures- GDH ^b	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
SOFAST Limited (63.09%) ^x	23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand
South Texas Shale LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Southeast Texas Biofuels LLC ^b	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 ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Sp/f Decision3 (GreenSteam) Company (61.68%) ^y	Krosslið 11, FO-100 Tórshavn , Faroe Islands

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14. Related undertakings of the group – continued

SRHP (99.99%) ^b	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
Standard Oil Company, Inc.	251 East Ohio Street, Suite 500, Indianapolis IN 46204, United States
Stryde Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Sunrise Oil Sands Partnership (50.00%) ^f	c/o Husky Oil Operations Limited, 707- 8th Avenue SW, Calgary AB T2P 1H5, Canada
Taradadis Pty. Ltd.	Level 17, 717 Bourke Street, Docklands VIC, Australia
Telcom General Corporation (99.96%) ^d	818 West Seventh Street, 2nd Floor, Los Angeles, CA, 90017
Terre de Grace Partnership (75.00%) ^f	1100, 635- 8th Avenue SW, Calgary AB T2P 3M3, Canada
The Anaconda Company	814 Thayer Avenue, Bismarck, ND, 58501-4018
The BP Share Plans Trustees Limited ^d	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%) ^b	153 Neftchilar Avenue, Baku, AZ1010, Azerbaijan
TJKK	15th Fl. Roppongi Hills Mori Tower, 10-1 Roppongi 6-chome, Minato-ku, Tokyo106-6115, Japan
Toledo Refinery Holding Company LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Torrelavega 7, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Union Texas International Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Vastar Pipeline, LLC ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Viceroy Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Villacarriedo 8, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Warrenville Development Limited Partnership ^b	33 North LaSalle Street, Chicago, Illinois 60602, United States
Water Way Trading and Petroleum Services LLC (90.00%)	Khur Al-Zubair, pear No 1, Basra, 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 ^b	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. ^b	5615 Corporate Blvd., Suite 400B, Baton Rouge LA 70808, United States
Wiriagar Overseas Ltd	Estera Corporate Services (BVI) Limited, Jayla Place, Wickhams Cay 1, PO Box 3190, Road Town, Tortola, VG1110, Virgin Islands, British

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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 (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
ABG Autobahn-Betriebe GmbH (32.58%) ^b	Brucknerstraße 4, 1041 Wien, Austria
Abu Dhabi Marine Areas Limited (33.33%) ^b	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Advanced Biocatalytics Corporation (24.20%) ^a	18010 Skypark Circle , #130 , Irvine CA 92614, United States
AEP I HoldCo LLC (24.30%) ^b	Harvard Business Services, Inc., 16192 Coastal Hwy, Lewes, Delaware, 19958, United States
AGES International GmbH & Co. KG, Langenfeld (24.70%) ^f	Berghausener Straße 96, 40764 Langenfeld, Germany
AGES Maut System GmbH & Co. KG, Langenfeld (24.70%) ^f	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 Sardegna 38, 00187, Roma, Italy
Air BP PBF del Peru S.A.C. (50.00%)	Avenida Ricardo Rivera Navarrete n.501 / room 1602, Lima, Peru, 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 Vijfhuizenweg 6, 1118LV Luchthaven, Schiphol, Netherlands
Aircraft Refuelling Company GmbH (33.33%) ^b	Trabrennstraße 6-8 3, A-1020, Wien, Austria
Aker BP ASA (30.00%)	Oksenoyveien 10, , 1366 Lysaker, Norway
Alaska LNG Project LLC (33.33%) ^b	Corporation Service Company, 2711 Centerville Road., Suite 400, Wilmington DE 19808, United States
Alaska Tanker Company, LLC (25.00%) ^b	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
Alyssum Group Ltd (26.20%) ^e	522 Fulham Road, London, SW6 5NR, United Kingdom
Ambarli Depolama Hizmetleri Limited Sirketi (50.00%)	Yakuplu Mahallesi Genc, Osman Caddesi, No.7 Beylikdüzü, Istanbul, Turkey
Ammenn GmbH (75.00%)	Luisenstraße 5 a, 26382 Wilhelmshaven, Germany
Apollo Geração de Energia Ltda (49.97%) ^b	Sitio Canto, número S/N, bairro / distrito Zona Rural, municipio Russas- CE, CEP 62900-000
Aragonesa de Gestión de Energías Alternativas, SL (49.97%)	Calle Alcalá numero 63, 28014, Madrid, Spain
ATAS Anadolu Tasfiyehanesi Anonim Sirketi (68.00%) ^f	Degirmen yolu cad. No:28 , Asia OfisPark K:3 İcerenkoy-Atasehir, Istanbul, 34752, Turkey
Atlantic 1 Holdings LLC (34.00%) ^b	RL&F Service Corp, 920 North King Street, 2nd Floor, Wilmington DE 19801, United States
Atlantic 2/3 Holdings LLC (42.50%) ^b	RL&F Service Corp, 920 North King Street, 2nd Floor, Wilmington DE 19801, United States
Atlantic 4 Holdings LLC (37.78%) ^b	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%) ^b	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%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Auwahi Wind Energy LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Aviation Fuel Services Limited (25.00%)	Calshot Way Central Area, Heathrow Airport, Hounslow, Middlesex, TW6 1PY, United Kingdom
Aviation Service (Iraq) Limited (40.00%) ^a	2World Business Centre Heathrow, Newall Road, London Heathrow Airport, Hounslow, TW6 2SF, United Kingdom
Axion Comercializacion De Combustibles Y Lubricantes S.A. (50.00%)	Avenida Luis Alberto de Herrera 1248, Oficina 1901, 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%) ^b	Arbea Campus Empresarial, Edificio 1. Ctra de Fuencarral a Alcobendas, M603, KM 3,8 28108 Alcobendas, MADRID, SPAIN
Axion Energy Paraguay S.R.L. (50.00%) ^b	Av. España 1369 esquina San Rafael, Asunción, Paraguay
Axuy Energy Holdings S.R.L. (50.00%) ^b	Avenida Luis Alberto de Herrera 1248, Oficina 1901, Montevideo, Uruguay
Axuy Energy Investments S.R.L. (50.00%) ^b	Avenida Luis Alberto de Herrera 1248, Oficina 1901, Montevideo, Uruguay
Azerbaijan Gas Supply Company Limited (23.06%) ^b	Maples & Calder, P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
Azerbaijan International Operating Company (30.37%) ^b	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. Mineralöl-Vertriebs-KG (50.00%) ^f	Saganer Straße 31, 90475 Nürnberg, Germany
BGFH Betankungs-Gesellschaft Frankfurt-Hahn GbR (50.00%) ^f	Sportallee 6, 22335 Hamburg, Germany
Bighorn Solar 1, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Billund Refuelling I/S (50.00%)	GA Centervej 1, DK-7190, Billund, Denmark
Blackbear Alabama Solar 1, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Blackbear Alabama Solar Land Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Blendcor (Pty) Limited (37.50%) ^a	135 Honshu Road, Islandview, Durban, 4052, South Africa

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14. Related undertakings of the group – continued

Blue Marble Holdings Limited (23.58%) ^g	Northgate House, 2nd Floor, Upper Borough Walls, Bath, BA1 1RG, United Kingdom
Blue Ocean Seismic Services Limited (52.50%) ^a	12-14 Carlton Place, Southampton, SO15 2EA, United Kingdom
Bodmin Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
BP AOC Pumpstation Maatschap (50.00%) ^f	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
BP Bunge Bioenergia S.A. (48.27%)	Avenida das Nações Unidas, n° 12.399, 4º andar, Brooklin Paulista, São Paulo, CEP 04578-000, Brazil
BP Dhofar LLC (49.00%)	P.O.Box 20302/211, 20302, Oman
BP Esso AOC Maatschap (22.80%) ^f	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
BP Esso Pipeline Maatschap (50.00%) ^f	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
BP Guangzhou Development Oil Product Co., Ltd (40.00%) ^b	Room X2072, 2/F, No.13 Longxue Road, Longxue Island, Nansha District, Guangzhou, Guangdong, 511450, China
BP Petro China Jiangmen Fuels Co., Ltd. (49.00%) ^b	Room A, building B , 5th floor, no. 22 gangang road, Jiangmen, China
BP PetroChina Petroleum Co., Ltd (49.00%) ^b	Room B1, 11th Floor, No.22 Gang Kou Yi Road, Peng Jiang District, Jiangmen, Guangdong Province, China
BP PETRONAS Acetyls Sdn. Bhd. (70.00%)	Level 8, Symphony House, Pusat Dagangan Dana 1, Jalan PJJ 1A/46 47301 Petaling Jaya, Selangor Darul Ehsan, Malaysia
BP Sinopec (ZheJiang) Petroleum Co., Ltd (40.00%) ^b	F12, Hua Zhe Square Tower 1, 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%) ^b	9# Huo Ju Road, Liu He District, Nanjing, Jiangsu Province, China
BP-Husky Refining LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP-Japan Oil Development Company Limited (50.00%) ^b	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
Braendstoflageret Kobenhavns Lufthavn I/S (20.83%) ^f	København, Lufthavn, 2770 Kastrup, Denmark
BTC International Investment Co. (30.10%) ^g	Maples & Calder, P.O. Box 309, Uglund House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
Burnthouse Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Butamax™ Advanced Biofuels LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Caesar Oil Pipeline Company, LLC (39.39%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Cairns Airport Refuelling Service Pty Ltd (33.33%)	Company Matters Pty Ltd, Level 12, 680 George Street, Sydney NSW 2000, Australia
Cantera K-3 Limited Partnership (39.00%) ^f	6400 Shafer Ct., Suite 400, Rosemont IL 60018-4927, United States
Canton Renewables, LLC (50.00%) ^b	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%) ^b	C1/C2-1, C1/C2-2, 1-6F, No. C1/C2 building, No.107 Huazhong Electronics Industry Park, Fangcao 2 Road, Wuhan Economic and Technological Development Zone, Wuhan, Hubei Province, China
Cedar Creek II Holdings LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Cedar Creek II, LLC (50.00%) ^b	1560 Broadway, Suite 2090, Denver, Colorado, 80202
Cefari RNG OKC, LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Cekisan Depolama Hizmetleri Limited Sirketi (35.00%)	Liman Mah. 60 Sk., Çekisan-Idari Bina sit. No:25 A/1, Konyaaltı, Antalya, Turkey
Central African Petroleum Refineries (Pvt) Ltd (20.75%)	Block 1Tendeseke Office Park, Samora Machel Av/Renfrew Road, Harare, Zimbabwe
CERF Shelby, LLC (50.00%) ^b	800 S. Gay Street, Suite 2021, Knoxville TN 37929, United States
Chicap Pipe Line Company (56.17%)	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 Ti-Ding Blvd., Neihu, 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 (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Clean Eagle RNG, LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Clean Vision Solar LLC (49.97%) ^b	400 Montgomery Street, Floor 8, San Francisco, CA 94104
Cleopatra Gas Gathering Company, LLC (37.28%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
CNAF Air BP General Aviation Fuel Company Limited (49.00%)	11/F, Building No.2, No. 32 Lingang Road Section One, Xihang Port Street, Shuangliu District, Chengdu, Sichuan Province, China
Coastal Oil Logistics Limited (25.00%)	10th Floor, The Bayleys Building, Cnr Brandon St and Lambton Quay, Wellington, 6011, New Zealand
Compatible Opportunity Lda (49.97%)	Rua Sousa Martins, no 10, 1050 218, Lisboa, Portugal
Compatibleglobe Lda (49.97%)	Rua Sousa Martins, no 10, 1050 218, Lisboa, Portugal
Concessionaria Stalvedro SA (50.00%)	San Gottardo Sud, 6780, Airolo, Switzerland
Continental Divide Solar I, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Continental Divide Solar II, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Continental Divide Solar Land Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
CSG Convenience Service GmbH (24.80%)	Wittener Straße 45, 44789 Bochum, Germany
Danish Refuelling Services I/S (50.00%) ^f	Kastrup Lufthavn, 2770 Kastrup, Denmark
Danish Tankage Services I/S (50.00%) ^f	Kastrup Lufthavn 1, 2770 Kastrup, Denmark
Dapsun- Investimentos e Consultoria, LDA. (24.99%)	Rua Júlio Dinis, n.º 247, 6.º, E-1, Edifício Mota Galiza, Parish of Lordelo do Ouro and Massarelos, 4050-027, Porto, Portugal
Dinarel S.A. (20.00%)	La Cumparsita 1373, piso 4º, Montevideo, Uruguay
Donoma Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
DOPARK GmbH (25.00%)	Westfalendamm 166, 44141 Dortmund, Germany
Dusseldorf Fuelling Services GbR (33.00%) ^f	Sportallee 6, 22335 Hamburg, Germany

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14. Related undertakings of the group – continued

Dusseldorf Tank Services GbR (33.00%) ^f	Sportallee 6, 22335 Hamburg, Germany
El Tensah Petroleum Company "PETROTEMSAH" (25.00%)	5 El Mokhayam El Daiem St, 6th Sector, Nasr City, Egypt
Elk Hill Solar 1, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Elk Hill Solar 2, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
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 (45.72%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Energías Renovables de Ixion, SL (49.97%)	Calle Alcalá numero 63, 28014, Madrid, Spain
Energy Emerging Investments, LLC (50.00%) ^b	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Entrepot pétrolier de Chambéry (32.00%)	562 Avenue du Parc de l'Ile, 92000, NANTERRE, France
Entrepôt Pétrolier de Puget sur Argens- EPPA (58.25%) ^t	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
Erdol-Lagergesellschaft m.b.H. (23.00%) ^b	Radlpaßstraße 6, 8502 Lannach, Austria
Etzel-Kavernenbetriebsgesellschaft mbH & Co. KG (33.33%) ^f	Bertrand-Russell-Straße 3, 22761 Hamburg, Germany
Etzel-Kavernenbetriebs-Verwaltungsgesellschaft mbH (33.33%)	Bertrand-Russell-Straße 3, 22761 Hamburg, Germany
EverSource Advisors Private Ltd (24.99%)	One Indiabulls Center, 16th Floor, Tower 2A, Senapati Bapat Marg, Mumbai City, Maharashtra, Mumbai, 400013, India
EverSource Management Holdings (24.99%)	3rd Floor, Standard Chartered Tower, Bank Street, 19 Cybercity, Ebene, 72201, Mauritius
Ffos Las Solar Developments Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
FFS Frankfurt Fuelling Services (GmbH & Co.) OHG (33.00%) ^f	Sportallee 6, 22335 Hamburg, Germany
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, United States
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%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Flat Ridge 2 Wind Holdings LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Flughafen Hannover Pipeline Verwaltungsgesellschaft mbH (50.00%)	Überseeallee 1, 20457, Hamburg, Hamburg, Germany
Flughafen Hannover Pipelinegesellschaft mbH & Co. KG (50.00%) ^f	Überseeallee 1, 20457, Hamburg, Hamburg, Germany
Fly Victor Ltd (26.20%)	60 Sloane Avenue, London, SW3 3XB, United Kingdom
Flytanking AS (50.00%)	Postboks 36, Stjoldal, 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 Complex, Mailiao, Yunlin Hsien, Taiwan
Fotech Group Limited (22.40%) ^a	5th Floor, Condor House, 10 St Paul's Churchyard, London, EC4M 8AL, United Kingdom
Fowler I Holdings LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler II Holdings LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge II Wind Farm LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge Wind Farm LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Free Power for Schools 13 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 14 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 15 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 17 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 19 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 4 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 5 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 6 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 7 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Freetricity Central June Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Freetricity Commercial June Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Fresh-Serve Bakeries LLC (37.04%) ^b	Corporation Service Company, 421 West Main Street, Frankfort KY 40601, United States
Fuelling Aviation Service- FAS (50.00%) ^b	3 Rue des Vignes, Aéroport Roissy Charles de Gaulle, 93290, TREMBLAY EN FRANCE, France
Fuerzas Energéticas del Sur de Europa IV, SL (49.97%)	Calle Alcalá numero 63, 28014, Madrid, Spain
Fuerzas Energéticas del Sur de Europa XIX, SL (49.97%)	Calle Alcalá numero 63, 28014, Madrid, Spain
Fundación para la Eficiencia Energética de la Comunidad Valenciana (33.33%) ^b	Calle Lituania nº 10, Castellón de la Plana, Spain
Gardermoen Fuelling Services AS (33.33%)	Postboks 133, Gardermoen, NO-2061, Norway
Gas Natural Acu Comercializadora de Energia Ltda. (50.00%)	Rua do Russel 804, 5th floor, Gloria, Rio de Janeiro, Brazil
Gas Natural Acu S.A. (30.00%)	Praia do Flamengo 66, 13th and 14th floors, Block A, Flamengo, Rio de Janeiro, Brazil
Gas Natural Infraestructura S.A. (28.51%)	Rua do Russel 804, 5th floor, Gloria, Rio de Janeiro, Brazil
Gemalsur S.A. (50.00%)	Colonia 810, Oficina 403, Montevideo, Uruguay
Georgian Pipeline Company (30.37%) ^b	190 Elgin Avenue, George Town, Grand Cayman, KY1-9005, Cayman Islands

The parent company financial statements of BP p.l.c. on pages 260-296 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

Gezamenlijke Tankdienst Schiphol B.V. (50.00%)	Anchoragelaan 6, 1118LD Luchthaven Schiphol, Netherlands
GISSCO S.A. (50.00%)	2,Vouliagmenis Ave & Papaflessa, 16777 Elliniko, Athens, Attika, Greece
Glade CD Solar Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Class B, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Construction Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Construction, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Holdings 1, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Holdings 2, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Land Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Gnowee Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Goshen Phase II LLC (50.00%) ^b	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
Great Ropemaker Partnership (G.P) Limited (50.00%) ^a	33 Cavendish Square, London, W1G 0PW, United Kingdom
Great Ropemaker Property (Nominee 1) Limited (50.00%)	33 Cavendish Square, London, W1G 0PW, United Kingdom
Great Ropemaker Property (Nominee 2) Limited (50.00%)	33 Cavendish Square, London, W1G 0PW, United Kingdom
Great Ropemaker Property Ltd (50.00%)	33 Cavendish Square, London, W1G 0PW, United Kingdom
Green Growth Feeder Fund Pte. Ltd (24.99%)	163 Penang Road, #08-01, Winsland House II, Singapore, 238463, Singapore
Grid Edge Limited (60.00%) ^a	Mclaren Building Suite, 14a Mclaren Building, 46 Priory Queensway, Birmingham, B4 7LR, United Kingdom
Groupement Pétrolier de Saint Pierre des Corps-GPSPC (20.00%) ^b	150 Avenue Yves Farge, 37700, SAINT PIERRE DES CORPS, France
Guangdong Dapeng LNG Company Limited (30.00%) ^b	10-11/FTIME Finance Center, No.4001 Shennan Dadao, Futian Street, Futian District, Shenzhen, Guangdong Province, China
GVÖ Gebinde-Verwertungsgesellschaft der Mineralölwirtschaft mbH (21.00%)	Steindamm 55, 20099 Hamburg, Germany
H7 Energy Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Hamburg Tank Service (HTS) GbR (33.00%) ^f	Sportallee 6, 22335 Hamburg, Germany
Hebei Dongming Yinglun Petroleum Co., Ltd. (49.00%) ^b	South Side, Floor 10, Insurance Industrial Park, No. 672, Chengjiao Street,, Qiaoxi District, Shijiazhuang City, Hebei Province, China
Heinrich Fip GmbH & Co. KG (50.00%) ^f	Rheinstraße 36, 49090 Osnabrück, Germany
Helix Power Limited (32.40%) ^a	Kelvin Building , Bramah Avenue , East Kilbride, Glasgow , Scotland, G75 0RD, United Kingdom
Henan Dongming Yinglun Petroleum Co., Ltd. (49.00%) ^b	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, Zhengzhou City
HFS Hamburg Fuelling Services GbR (25.00%) ^f	Sportallee 6, 22335 Hamburg, Germany
Hiergeist Heizolhandel GmbH & Co. KG (50.00%) ^f	Grubenweg 4, 83666 Waakirchen-Marienstein, Germany
Hokchi Energy S.A. de C.V. (50.00%)	Torre A, piso 4, oficina 402, Calzada Legaria 549, Colonia 10 de Abril, Delegación Miguel Hidalgo, Ciudad de Mexico, C. P. 11250, Mexico
Hokchi Iberica S.L. (50.00%)	Campus Empresarial Arbea- Edificio N° 1, Carretera Fuencarral a Alcobendas (M-603), Km 3,8., Alcobendas, Madrid, Spain
Howbery Solar Park Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Impact Solar 1, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Impact Solar Class B, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Impact Solar Construction, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Impact Solar Holdings 1, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Impact Solar Holdings 2, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Impact Solar Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Implantación de Fuentes Energéticas de Origen Renovable, SL (49.97%)	Calle Alcalá número 63, 28014, Madrid, Spain
In Salah Gas Limited (25.50%) ^a	IFC 5, St Helier, Jersey, JE1 1ST, Jersey
In Salah Gas Services Limited (25.50%) ^a	IFC 5, St Helier, Jersey, JE1 1ST, Jersey
India Gas Solutions Private Limited (50.00%)	Unit Nos.71 & 737th Floor, Maker Maxity, 2nd North Avenue, Bandra- Kurla Complex, Bandra (East), Mumbai 400 051, Maharashtra, India
Jamaica Aircraft Refuelling Services Limited (51.00%) ^b	PCJ Building36 Trafalgar Road, Kingston 10, Jamaica
Johnson Corner Solar I, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808, United States
Kala Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
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
Köhn & Plambeck GmbH & Co. KG (50.00%) ^f	An der Braker Bahn 22, 26122 Oldenburg, Germany
Kurt Ammenn GmbH & Co. KG (50.00%) ^f	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%) ^f	Sportallee 6, 22335 Hamburg, Germany
Lightning Hybrids, LLC (31.60%) ^a	160 Greentree Drive, Suite 101, Dover, County of Kent DE 19904, United States
Lightsource Asset Holdings (Australia) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Asset Holdings (Europe) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

The parent company financial statements of BP p.l.c. on pages 260-296 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 Asset Holdings (Spain) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Asset Holdings (UK) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Asset Holdings (USA) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Asset Holdings (Vendimia I) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Asset Holdings (Vendimia II) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Asset Holdings 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Asset Holdings 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Asset Holdings 3 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Asset Management Australia Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Lightsource Asset Management Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Australia FinCo Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Australia SPV 1 Pty Limited (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Lightsource Australia SPV 2 Pty Limited (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Lightsource Australia SPV 3 Pty Limited (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Lightsource Australia SPV 4 Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Lightsource Beacon Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Lightsource Beacon, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Lightsource Bodegas Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Bom Lugar IV Geração de Energia Ltda (49.97%)	Fazenda Terra Nova, located at Rod. Padre Cícero (CE 153), S/N, KM 58, Lima Campos, City of Icó, State of Ceará, Zip Code 63.435-000
Lightsource Bom Lugar IX Geração de Energia Ltda (49.97%)	Fazenda Terra Nova, located at Rod. Padre Cícero (CE 153), S/N, KM 58, Lima Campos, City of Icó, State of Ceará, Zip Code 63.435-000
Lightsource Bom Lugar V Geração de Energia Ltda (49.97%)	Fazenda Terra Nova, located at Rod. Padre Cícero (CE 153), S/N, KM 58, Lima Campos, City of Icó, State of Ceará, Zip Code 63.435-000
Lightsource Bom Lugar VI Geração de Energia Ltda (49.97%)	Fazenda Terra Nova, located at Rod. Padre Cícero (CE 153), S/N, KM 58, Lima Campos, City of Icó, State of Ceará, Zip Code 63.435-000
Lightsource Bom Lugar VII Geração de Energia Ltda (49.97%)	Fazenda Terra Nova, located at Rod. Padre Cícero (CE 153), S/N, KM 58, Lima Campos, City of Icó, State of Ceará, Zip Code 63.435-000
Lightsource Bom Lugar VIII Geração de Energia Ltda (49.97%)	Fazenda Terra Nova, located at Rod. Padre Cícero (CE 153), S/N, KM 58, Lima Campos, City of Icó, State of Ceará, Zip Code 63.435-000
Lightsource BP Hassan Allam Developments for Renewable Energy S.A.E (24.99%)	14 Kamal El Tawil ST, Zamalek, Cairo, Egypt
Lightsource BP Hassan Allam Holdings B.V. (24.99%)	Jan van Goyenkade 8, 1075HP, Amsterdam, Netherlands
Lightsource BP Renewable Energy Investments Limited (49.97%) ^c	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Brasil Energia Renovavel Participacoes S.A. (49.97%)	Av. Bernardino de Campos, n. 98., Conj. A, 12 Andar, Sala 37, Paraíso, São Paulo, 04.004-040, Brazil
Lightsource Brazil Holdings 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Brazil Holdings 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Commercial Rooftops (Buyback) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Commercial Rooftops Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Construction Management Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Development Services Australia Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Lightsource Development Services Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Egypt Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Europe Asset Management, SL (49.97%)	Calle Suero de Quinones, Numero 34-36, 28002, Madrid, Spain
Lightsource Finance 55 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Finca Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Grace 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Grace 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Grace 3 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Holdings 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Holdings 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Holdings 3 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Impact 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Impact 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource India Holdings (Mauritius) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource India Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource India Investments (UK) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource India Limited (25.48%) ^b	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource India Maharashtra 1 Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

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14. Related undertakings of the group – continued

Lightsource India Maharashtra 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Kingfisher Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Kingpin 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Kingpin 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Kingpin 3 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Labs 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Labs Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Labs Limited (47.47%)	Trinity House, Charleston Road, Ranelagh, Dublin 6, D06C8X4, Ireland
Lightsource Largescale Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource LS Labs Australia Operations Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Lightsource LS Labs Australia Pty LTD (49.97%)	C/- Baker McKenzie, Level 19, 181 William Street, Melbourne VIC 3000, Australia
Lightsource Midscale Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Milagres I Geracao de Energia Ltda. (49.97%)	Sitio Cajueiro- Abaiara- left of BR 116, KM491, Caatinga Grande, Zona Rural, Abaiara, 63.240-000, Brazil
Lightsource Milagres II Geracao de Energia Ltda. (49.97%)	Sitio Cajueiro- Abaiara- left of BR 116, KM491, Caatinga Grande, Zona Rural, Abaiara, 63.240-000, Brazil
Lightsource Milagres III Geracao de Energia Ltda. (49.97%)	Sitio Cajueiro- Abaiara- left of BR 116, KM491, Caatinga Grande, Zona Rural, Abaiara, 63.240-000, Brazil
Lightsource Milagres IV Geracao de Energia Ltda. (49.97%)	Sitio Cajueiro- Abaiara- left of BR 116, KM491, Caatinga Grande, Zona Rural, Abaiara, 63.240-000, Brazil
Lightsource Milagres V Geracao de Energia Ltda. (49.97%)	Sitio Cajueiro- Abaiara- left of BR 116, KM491, Caatinga Grande, Zona Rural, Abaiara, 63.240-000, Brazil
Lightsource Nala Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Operations 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Operations 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Operations 3 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Operations Services Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Property 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Property 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Property Investment Holdings Ltd (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Property Investment Management (LPIM) LLP (49.97%) ^f	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Property Investments 1 Ltd (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Pumbaa Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Radiate 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Radiate 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Raindrop Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy (Australia) Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Lightsource Renewable Energy (India) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource Renewable Energy Asset Management Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Lightsource Renewable Energy Asset Management, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Lightsource Renewable Energy Assets Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Lightsource Renewable Energy Australia Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy Development, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808, United States
Lightsource Renewable Energy Garnacha, S.L. (49.97%)	Calle Alcalá número 63, 28014, Madrid, Spain
Lightsource Renewable Energy Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy Iberia Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy India Assets Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy India Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy India Opco Private Limited (49.97%)	No.44/38, 1st Floor, Veerabhadran Street, Valluvarkottam, Nungambakkam, Chennai, 600034, India
Lightsource Renewable Energy India Projects Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy Ireland Limited (49.97%)	Trinity House, Charleston Road, Ranelagh, Dublin 6, D06C8X4, Ireland
Lightsource Renewable Energy Italy Development, S.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy

The parent company financial statements of BP p.l.c. on pages 260-296 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 Renewable Energy Italy Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Renewable Energy Italy Holdings S.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Lightsource Renewable Energy Italy SPV 1 s.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Lightsource Renewable Energy Italy SPV 10 s.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Lightsource Renewable Energy Italy SPV 2 s.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Lightsource Renewable Energy Italy SPV 3 s.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Lightsource Renewable Energy Italy SPV 4 s.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Lightsource Renewable Energy Italy SPV 5 s.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Lightsource Renewable Energy Italy SPV 6 s.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Lightsource Renewable Energy Italy SPV 7 s.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Lightsource Renewable Energy Italy SPV 8 s.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Lightsource Renewable Energy Italy SPV 9 s.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Lightsource Renewable Energy Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Renewable Energy Management LLC (49.97%) ^b	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware 19902, United States
Lightsource Renewable Energy Netherlands Development B.V. (49.97%)	Prins Bernhardplein 200, 1097JB, Amsterdam, Netherlands
Lightsource Renewable Energy Netherlands Holdings B.V. (49.97%)	Prins Bernhardplein 200, 1097JB, Amsterdam, Netherlands
Lightsource Renewable Energy Netherlands Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy Operations LLC (49.97%) ^b	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware 19902, United States
Lightsource Renewable Energy Portugal Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy Services Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Lightsource Renewable Energy Services, Inc. (49.97%)	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Lightsource Renewable Energy Spain Development, SL (49.97%)	Calle Alcalá número 63, 28014, Madrid, Spain
Lightsource Renewable Energy Spain Holdings, SL (49.97%)	Calle Alcalá número 63, 28014, Madrid, Spain
Lightsource Renewable Energy Spain SPV 1, SL (49.97%)	Calle Alcalá número 63, 28014, Madrid, Spain
Lightsource Renewable Energy Trading, SL (49.97%)	C/Pradillo 5, Bajo Exterior Derecha, 28002, Madrid, Spain
Lightsource Renewable Energy US, LLC (49.97%) ^b	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware 19902, United States
Lightsource Renewable Global Development Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Services Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Renewable UK Development Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Residential NI Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource Residential Rooftops (Buyback) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Residential Rooftops (PPA) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Residential Rooftops Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Simba Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Singapore Renewables Holdings Private Limited (49.97%)	8 Marina Boulevard, #05-02 Marina Bay Financial Centre, Singapore
Lightsource Singapore Renewables Private Limited (49.97%)	8 Marina Boulevard, #05-02 Marina Bay Financial Centre, Singapore
Lightsource Spain O&M, SL (49.97%)	Calle Suero de Quinones, Numero 34-36, 28002, Madrid, Spain
Lightsource SPV 10 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 100 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 101 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 105 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 106 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 108 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 109 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

The parent company financial statements of BP p.l.c. on pages 260-296 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 SPV 54 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 56 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 60 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 69 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 73 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 74 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 75 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 76 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 78 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 79 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 8 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 88 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 91 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 92 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 98 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Timon Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Trading Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Viking 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Viking 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Limited Liability Company TYNGD (20.00%) ^b	Pervomayskaya street, 32A, 678144, Lensk, Sakha (Yakutiya) Republic, Russian Federation
Limited Liability Company Yermak Neftegaz (49.00%) ^b	Kosmodamianskaya nab, 52/3, 115035, Moscow, Russian Federation
LL Property Services 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
LL Property Services Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
LLC "Kharampurneftegaz" (49.00%) ^b	629830 Yamalo-Nenetskiy Anatomy Region, city of Gubkinskiy, Russian Federation
Lora Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lotos- Air BP Polska Spółka 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 (37.93%)	815-816 International Trade Tower, Nehru Place, New Delhi, New Delhi, 110019, India
LS Australia FinCo 1 Pty Limited (49.97%)	C/- Baker McKenzie, Level 19, 181 William Street, Melbourne VIC 3000, Australia
LS Australia HoldCo1 Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
LSBP NE Development LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Maasvlakte Europoort Pipeline Maatschap (50.00%) ^f	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
Maatschap Europoort Terminal (50.00%) ^f	Moezelweg 101, 3198LS Europoort, Rotterdam, Netherlands
Mach Monument Aviation Fuelling Co. Ltd. (70.00%)	Naz City, Building J, Suite 10 Erbil, Iraq
Malmö 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 (49.97%)	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%) ^b	Praca Dos Trabalhadores, Nr 09, Distrito Urbano 1, Maputo, Mozambique
Masana Employee Share Trust No. 1 (37.88%) ^b	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, South Africa
Mavrix, LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
McFall Fuel Limited (49.00%)	KPMG, 247 Cameron Road, Tauranga, 3110, New Zealand
Mediterranean Gas Co. "MEDGAS" (25.00%)	5 El Mokhayam El Daiem St, 6th Sector, Nasr City, Egypt
Mehoopany Wind Energy LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Mehoopany Wind Holdings LLC (50.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Meri Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Middle East Lubricants Company LLC (29.33%)	6th Flr City Tower, 2- Sheikh Zayed Road, PO Box 1699, Dubai, United Arab Emirates
Milne Point Pipeline, LLC (50.00%) ^b	900 E. Benson Boulevard, Anchorage, Alaska, 99508, United States
Mobene Beteiligungs GmbH & Co. KG (50.00%) ^f	Spaldingstraße 64, 20097 Hamburg, Germany
Mobene Beteiligungs Verwaltungs GmbH (50.00%)	Spaldingstraße 64, 20097 Hamburg, Germany
Mobene GmbH & Co. KG (50.00%) ^f	Spaldingstraße 64, 20097 Hamburg, Germany
Mobene Verwaltungs-GmbH (50.00%)	Spaldingstraße 64, 20097 Hamburg, Germany
MTS Francis Court Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
MTS Trefinnick Solar Limited (49.97%)	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
Nextpower Trevenper Limited (49.97%)	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 (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Nord-West Oelleitung GmbH (59.33%)	Zum Ölhafen 207, 26384 Wilhelmshaven, Germany
Ocwen Energy Pty Ltd (49.50%)	GTH Accounting Group Pty Ltd '2', 1A Kitchener Street, Toowoomba QLD 4350, Australia
Olympic Pipe Line Company LLC (70.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States

The parent company financial statements of BP p.l.c. on pages 260-296 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

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, Edificio Torre , e/ Jaime Román y Víctor Pinto, Equipetrol Norte, Santa Cruz de la Sierra, Bolivia
Palk Power Limited (49.97%)	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%) ^b	Rua Manoel da Nóbrega n°1280, 10° andar, Sao Paulo, Sao Paulo, 04001-902, Brazil
Pan American Energy Group, S.L. (50.00%) ^a	Arbea Campus Empresarial, Edificio 1. Ctra de Fuencarral a Alcobendas, M603, KM 3,8 28108 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 N° 1, Carretera Fuencarral a Alcobendas (M-603), Km 3,8., Alcobendas, Madrid, Spain
Pan American Energy Investments Ltd. (50.00%)	Trinity Place Annex, Corner of Frederick & Shirley Streets, P.O. Box N-4805, Nassau, Bahamas
Pan American Energy Uruguay S.A. (50.00%)	Colonia 810, Oficina 403, Montevideo, Uruguay
Pan American Energy US LLC (51.00%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Pan American Energy, S.L. (50.00%) ^b	Arbea Campus Empresarial, Edificio 1. Ctra de Fuencarral a Alcobendas, M603, KM 3,8 28108 Alcobendas, MADRID, SPAIN
Pan American Fuegoina 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
Parque Eolico Del Sur S.A. (27.50%)	0
Peninsular Aviation Services Company Limited (25.00%) ^f	P O Box 6369, Jeddah21442, Saudi Arabia
Pentland Aviation Fuelling Services Limited (50.00%) ^c	6th Floor (c/o Q8 Aviation), Dukes Court, Duke Street, Woking, GU21 5BH, Surrey
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 (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Porteiras Geração de Energia Ltda (49.97%)	Estrada BR 135, número S/N, KM 250, bairro / distrito Angico de Minas, município Japonvar- MG, CEP 39335-000
Prince William Sound Oil Spill Response Corporation (25.00%)	9360 Glacier Highway, Suite 202, Juneau AK 99801, United States
Proteus Oil Pipeline Company, LLC (45.72%) ^b	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. Dirgantara Petroindo Raya (49.90%)	Wisma AKR, 25th floor, Jalan Panjang No.5, Kebon Jeruk, Jakarta Barat, 11530, Indonesia
PTE Pipeline LLC (32.00%) ^b	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
R&B Technology Holding CO., LTD (59.02%) ^a	PO Box 472, 2nd Floor, Harbour Place, 103 South Church Street, George Town, Grand Cayman, KY1-1106, Cayman Islands
Rahamat Petroleum Company (PETROHAMAMAT) (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%)	399 Moray Place, Dunedin, 9016, New Zealand
Resolution Partners LLP (68.00%) ^f	1675 Broadway, Denver CO 80202, United States
Rhein-Main-Rohrleitungstransportgesellschaft mbH (35.00%)	Godorfer Hauptstraße 186, 50997 Köln, Germany
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, Russian Federation
Routex B.V. (25.00%)	Strawinskylaan 1725, 1077XX Amsterdam, Netherlands
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.º Sala Saba, Lisboa, Portugal
SAFCO SA (33.33%)	International airport "El. Venizelos", Athens, Greece
Salzburg Fuelling GmbH (33.00%) ^b	Innsbrucker Bundesstraße 95, 5020 Salzburg, Austria
SAMCOL - Sociedade de Armazenamento e Manuseamento de Combustiveis Liquidos, Limitada (50.00%) ^b	Parcela 729, via onze mil cento e trinta, numero cento e qua, Matola Lingamo, Mozambique
Saraco SA (20.00%)	route de Pré-Bois 17, 1216, Cointrin, Switzerland
SeaPort Midstream Partners, LLC (49.00%) ^b	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware, 19904, United States
Sel PV 09 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Servicios Logísticos de Combustibles de Aviación, S.L (50.00%)	Paseo de la Castellana 278, Madrid, Spain, Spain
Shakti Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Shandong Dongming Yinglun Petroleum Co., Ltd. (49.00%) ^b	Room B-703, B-704, B-705, B-706, B-707, Floor 7, Block B, No.8, Luoyuan Avenue, Lixia District, Jinan City, China
Sharjah Aviation Services Co. LLC (49.00%) ^a	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%) ^b	1 Refinery Road, Prospecton, 4110, South Africa
Shell Mex and B.P. Limited (40.00%) ^a	Shell Centre, London, SE1 7NA, United Kingdom

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14. Related undertakings of the group – continued

Shenzhen Cheng Yuan Aviation Oil Company Limited (25.00%) ^b	Fu Yong Town, Bao An county, ShenZhen Airport, Guangdong Province, China
Shenzhen Dapeng LNG Marketing Company Limited (30.00%) ^b	Guangdong Dapeng Liquefied Natural Gas Filling Station, Cheng Tou Corner, Xia Sha Village, Dapeng Street, Dapeng New District, Shenzhen, China
Sherbino I Wind Farm LLC (50.00%) ^b	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 Centre, London, SE1 7NA, England
Société d'Avitaillement et de Stockage de Carburants Aviation "SASCA" (40.00%) ^b	1 Place Gustave Eiffel, 94150, RUNGIS, France
Société de Gestion de Produits Pétroliers - SOGEP (37.00%)	27 Route du Bassin Numéro 6, 92230, GENNEVILLIERS, France
Solar Photovoltaic (SPV2) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Solar Photovoltaic (SPV3) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Solar Strategic Energy LLC (49.97%) ^b	400 Montgomery Street, Floor 8, San Francisco, CA 94104
South Caucasus Pipeline Company Limited (28.83%) ^a	Maples & Calder, P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
South Caucasus Pipeline Holding Company Limited (28.83%)	Maples & Calder, 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%)	Maples & Calder, 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%) ^b	2-5F, No. 571, Yuncheng Dong Road, Baiyun District, Guangzhou City, Guangdong Province, China
Stansted Intoplane Company Limited (20.00%)	Causeway House, 1 Dane Street, Bishop's Stortford, Hertfordshire, CM23 3BT, United Kingdom
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, Virgin Islands, British
Sula Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Sun and Soil Renewable 12 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Tankanlage AG Mellingen (33.33%)	Birmenstorferstrasse 2, 5507, Mellingen, Switzerland
TAR - Tankanlage Ruemlang AG (27.32%)	Zwüscheiteich, 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%) ^f	Wesermünder Straße 1, 27729 Hambergen, Germany
Terminal CP S.A.U. (50.00%)	Av. Leandro N. Alem 1180, piso 11°, Buenos Aires, Argentina
Terminales Canarias, S.L. (50.00%)	Carretera de San Andrés/n, La Jurada-María Jiménez, Santa Cruz de Tenerife, Spain
TFSS Turbo Fuel Services Sachsen GbR (20.00%) ^f	Sportallee 6, 22335 Hamburg, Germany
TGC Solar 106 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
TGC Solar 91 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
TGFH Tanklager-Gesellschaft Frankfurt-Hahn GbR (50.00%) ^f	Sportallee 6, 22335 Hamburg, Germany
TGH Tankdienst-Gesellschaft Hamburg GbR (33.33%) ^f	Sportallee 6, 22335 Hamburg, Germany
TGHL Tanklager-Gesellschaft Hannover-Langenhagen GbR (50.00%) ^f	Sportallee 6, 22335 Hamburg, Germany
TGK Tanklagergesellschaft Köln-Bonn (25.00%) ^f	Sportallee 6, 22335 Hamburg, Germany
Thames Electricity Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
The Baku-Tbilisi-Ceyhan Pipeline Company (30.10%) ^b	Maples & Calder, P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
The Consolidated Petroleum Company Limited (50.00%) ^a	Shell Centre, London, SE1 7NA, United Kingdom
The Consolidated Petroleum Supply Company Limited (50.00%) ^b	Shell Centre, London, SE1 7NA, United Kingdom
The Great Ropemaker Partnership (50.00%) ^f	33 Cavendish Square, London, W1G 0PW, United Kingdom
Thornton Transportation LLC (37.04%) ^b	Corporation Service Company, 421 West Main Street, Frankfort KY 40601, United States
Thorntons LLC (37.04%) ^b	CSC, 251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
TLK Holding Company LLC (37.04%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
TLK Intermediate Holding Company LLC (37.04%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
TLK Operating Company LLC (37.04%) ^b	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
TLM Tanklager Management GmbH (49.00%) ^b	Am Tankhafen 4, 4020 Linz, Austria
TLS Tanklager Stuttgart GmbH (45.00%)	Zum Ölhafen 49, 70327 Stuttgart, Germany
Tonatiuh Trading 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
TRaBP GbR (75.00%) ^f	Huestraße 25, 44787, Bochum, Germany
Trafineo GmbH & Co. KG (75.00%) ^f	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
TransTank GmbH (50.00%)	Am Stadthafen 60, 45881 Gelsenkirchen, Germany
Tricoya Ventures UK Limited (36.73%)	Brettenham House, 19 Lancaster Place, London, WC2E 7EN, United Kingdom
Tuwalé Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

The parent company financial statements of BP p.l.c. on pages 260-296 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

TWQE2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Ubiworx Systems Designated Activity Company (47.47%)	Trinity House, Charleston Road, Ranelagh, Dublin 6, D06C8X4, Ireland
United Gas Derivatives Company "UGDC" (33.33%)	Building No. 349 & 351, Third Sector of City Centre, Fifth Settlement, Cairo, Egypt
United Kingdom Oil Pipelines Limited (22.15%)	5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS, United Kingdom
Vale do Cochá Geração de Energia Ltda (49.97%)	Estrada BR 030, número S/N, CXPST 08, bairro / distrito Zona Rural, município Montalvania- MG, CEP 39495-000
Vendimia Grid, AIE (49.97%)	Calle Alcalá número 63, 28014, Madrid, Spain
Verde Grande Geração de Energia Ltda (49.97%)	Fazenda Contendas, localizada na Rodovia Joaquim de Freitas, sentido Mato Verde a Catuti, Km 2 à direita, Zona Rural, município de Mato Verde-MG, CEP 39527-000
VIC CBM Limited (50.00%)	Eni House, 10 Ebury Bridge Road, London, SW1W 8PZ, United Kingdom
Vientos Ombu III S.A. (25.00%)	Av. Leandro N. Alem 1180, piso 11°, Buenos Aires, Argentina
Vientos Patagonicos Chubut Norte III S.A. (24.50%)	Lavalle 190, piso 6 Depto L, Buenos Aires
Vientos Sudamericanos Chubut Norte IV S.A. (24.50%)	Lavalle 190, piso 6 Depto L, Buenos Aires
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, Herts., HP2 5BS, United Kingdom
Wellington LandCo Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
West London Pipeline and Storage Limited (30.50%)	5-7 Alexandra Road, Hemel Hempstead, Herts., HP2 5BS, United Kingdom
Whitetail Solar 1, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Whitetail Solar 2, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Whitetail Solar 3, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Whitetail Solar 6, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Whitetail Solar Land Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Wick Farm Grid Limited (24.99%)	Woodwater House, Pynes Hill, Exeter, EX2 5WR, United Kingdom
Wildflower Solar I, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Wildflower Solar Land Holdings, LLC (49.97%) ^b	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Wiri Oil Services Limited (27.78%)	Ross Pauling & Partners Limited, 106b Bush Road, Albany, Auckland, 0632, New Zealand
Yangtze River Acetyls Co., Ltd (51.00%) ^b	97 Weijiang Road (in the Petrochemical Park), Changshou District, Chongqing, China
Your Power No. 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 10 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 19 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 3 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 8 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No12 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Zonnevide Westdorperveen B.V. (49.97%)	Prins Bernhardplein 200, 1097JB, Amsterdam, Netherlands
Zubie, Inc. (20.30%)	160 Greentree Drive, Suite 101, Dover, County of Kent DE 19904, United States

^a Preference shares

^b Member interest

^c A and B shares

^d Common stock and preference shares

^e Ordinary shares and preference shares

^f Partnership interest

^g A, B and D shares

^h A shares

ⁱ Interest held directly by BP p.l.c.

^j 99% held directly by BP p.l.c.

^k 1% held directly by BP p.l.c.

^l Ordinary, A and B shares

^m Common stock and redeemable preference shares

ⁿ Ordinary A, B and C shares

^o 0.008% held directly by BP p.l.c.

^p 80.01% ordinary shares and 99.07% preference shares

^q Members interest, (49.99%) subordinated units and (4.37%) common units traded on the New York stock exchange

^r 93.64% ordinary shares and 81.18% preference shares

^s Subsidiary in which the group does not hold a majority of the voting rights but exercises control over it

^t Ordinary shares and redeemable preference shares

^u Ordinary and A shares

^v Ordinary and deferred shares

^w Subsidiary undertaking pursuant to sections 1162(2), 1162(3)(b) and Paragraph 6 of Schedule 7 of the Companies Act 2006

^x 100% ordinary shares and 58.65% preference shares

^y 92.31% B shares and 78.43% D shares

^z 15% held directly by BP p.l.c.

^{aa} B shares

^{ab} Unlimited redeemable shares

^{ac} 96.52% C shares

^{ad} 1.89% A shares and 40.80% B shares

^{ae} 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

^{af} 5% held directly by BP p.l.c.

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