The Thunder Horse platform is located in the US Gulf of Mexico, around 150 miles southeast of New Orleans, in over 6,000 feet of water.

Consolidated financial statements of the bp group

Notes on financial statements

Supplementary information on oil and natural gas (unaudited)

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

Consolidated financial statements of the bp group

Independent auditor's report to the members of BP p.l.c.

Report on the audit of the financial statements

1. 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 2020 and of the group's loss for the year then ended.
- The group financial statements have been properly prepared in accordance with international accounting standards in conformity with the requirements of the Companies Act 2006, International Financial Reporting Standards (IFRSs) as adopted by the European Union and IFRS as issued by the International Accounting Standards Board (IASB).
- The parent company financial statements have been properly prepared in accordance with United Kingdom accounting standards (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. As regards the parent company financial statements, the financial reporting framework that has been applied in their preparation is applicable law and United Kingdom accounting standards (United Kingdom generally accepted accounting practice), including FRS 101 'Reduced Disclosure Framework'.

2. 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.

3. Summary of our audit approach

Key audit matters	The key audit matters that we identified in the current year were: • COVID-19 and the resulting significant changes to the business environment; • Potential impact of climate change and the energy transition; • Impairment of upstream oil and gas property, plant and equipment (PP&E) assets; • Write-off of exploration and appraisal (E&A) assets; • Accounting for structured commodity transactions (SCTs) within the trading and shipping (T&S) function, and the valuation of other level 3 financial instruments, where fraud risks may arise in revenue recognition; • IT controls relating to financial systems; and • Management override of controls. This year we identified COVID-19 and the related significant changes to the business environment as a key audit matter, given the consequential impact on the financial statements and the focus on this issue by management and by external stakeholders. All other key audit matters are consistent with those we identified in the prior year.
Materiality	The materiality that we used for the group financial statements was $600 million (2019 $850 million) which was determined based on net assets. We adopted a different basis to determine the materiality used to audit the group financial statements this year. In the prior year we used profit-based metrics but this year we used net assets due to the significant losses incurred as a consequence, inter alia, of the COVID-19 pandemic and in particular the decrease in oil and gas prices.

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Scoping	Our scope covered 277 consolidation units (cons units). Of these, 173 were full-scope audits and the remaining 104 were subject to specific procedures on certain account balances by component audit teams or the group audit team. These covered 82% of group revenue and 75% of PP&E. The remaining 642 cons unit were subject to other procedures, including conducting analytical reviews, making inquiries, and evaluating and testing management's group-wide controls.

4. Conclusions relating to going concern

In auditing the financial statements, we have concluded that the directors’ use of the going concern basis of accounting in the preparation of the financial statements is appropriate.

Our evaluation of the directors’ assessment of the group’s and parent company’s ability to continue to adopt the going concern basis of accounting included:

- an assessment of whether material uncertainties existed that could cast significant doubt on the entity’s ability to continue as a going concern for at least 12 months after the date of approval of the financial statements;
- an assessment of the financing facilities including nature of facilities, repayment terms and covenants;
- testing of clerical accuracy and appropriateness of the model used to prepare the forecasts;
- an assessment of the assumptions used in the forecasts;
- an assessment of management’s identified potential mitigating actions and the appropriateness of the inclusion of these in the going concern assessment;
- an assessment of the historical accuracy of forecasts prepared by management;
- reperformance of management’s sensitivity analysis; and
- an assessment of the disclosures made within the financial statements

Based on our assessment, we concluded that the assumptions used by management were in the acceptable range and the disclosures made within the financial statements were appropriate.

Based on the work we have performed, we have not identified any material uncertainties relating to events or conditions that, individually or collectively, may cast significant doubt on the group's and parent company’s ability to continue as a going concern for a period of at least twelve months from when the financial statements are authorised for issue.

In relation to the reporting on how the group has applied the UK Corporate Governance Code, we have nothing material to add or draw attention to in relation to the directors’ statement in the financial statements about whether the directors considered it appropriate to adopt the going concern basis of accounting.

Our responsibilities and the responsibilities of the directors with respect to going concern are described in the relevant sections of this report.

5. 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.

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.

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5.1 Impact of COVID-19 and the resulting significant changes to the business environment	
Key audit matter description	The COVID-19 pandemic has significantly impacted the oil and gas industry. The principal area in which this has impacted bp is the demand destruction which led to low oil and gas prices in the year and an expectation that there will be an enduring impact going forward reducing forecast oil and gas prices. Accordingly this has impacted certain key estimates and judgements reliant on oil and gas prices. The lower oil and gas prices resulted in a loss for the year and the lower oil and gas price forecasts have resulted in significant PP&E impairments and reduced the attractiveness of developing certain E&A assets, leading to significant write-offs. The related principal risks that we have identified for our audit are as follows: • The 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 COVID-19 (see 'Impairment of upstream oil and gas PP&E assets' below); • The E&A asset write-offs are not aligned with management's intentions. In addition there is a risk around the commercial viability of E&A assets that remain on the balance sheet (see 'write-off of E&A assets' below); and • The unobservable inputs including long term commodity prices and the associated liquidity in the market, volatility and correlations, which are critical in determining the valuation of level 3 financial instruments may not reflect how market participants would reflect the effect, if any, of COVID-19 (see 'valuation of other level 3 financial instruments' below). Management also assessed the following potential risks that could arise from the impact of COVID-19 and the resulting significant changes to the business environment, which we determined also to be audit risks: • The liquidity of the business and future cash flow projections associated with the going concern assumption may not reflect fully the impact of COVID-19. As a consequence, inter alia, of the COVID-19 pandemic and its implications, management significantly increased liquidity, including securing a new $10 billion revolving credit facility in March 2020, issuing $6.8 billion of bonds in April 2020 and issuing $11.9 billion of hybrid bonds in June 2020. In addition management performed a reverse stress test as set out in Note 1; • The carrying value of the downstream PP&E refining assets may no longer be recoverable, due to changes in supply and demand which have resulted from COVID-19. Furthermore, the useful economic lives of these assets could be reduced (see 'Potential impact of climate change' below); • Decommissioning obligations transferred to third parties as part of bp's historical disposal transactions could potentially return to bp under relevant laws and regulations in the event the buyer is unable to complete decommissioning works due to the possibility of COVID-19 impacting their liquidity and financial stability; • The increased risk of credit losses following increased counterparty credit risk due to commodity price volatility, unprecedented demand destruction and bankruptcies of trading organisations. As described in Note 21, management recognises that credit risk has increased since 31 December 2019 but as there has also been a significant reduction in the group's trade and other receivables balance, the total allowance for expected credit losses has not increased significantly in the year; • The shift to key business processes being performed virtually and the associated impact on the control environment. In particular, in an environment of volatile commodity prices, there is an increased risk of non-compliance with policies and procedures by traders within the T&S function, resulting in the risk of breaches in trader limits, as the monitoring and surveillance of front office activities becomes more challenging; and • During the year, a number of oil trading entities in Singapore have declared bankruptcies. After the bankruptcies, allegations have been made that certain of the funding arrangements of these oil trading entities involved finance schemes whereby funds were raised backed by assets that did not exist or were supported by fraudulent sales. These finance schemes typically involved back-to-back intra-group arrangements transacted with an independent third party. There is a risk that bp, as a significant participant in the oil trading sector in Singapore, may have been a counterparty to such transactions, resulting in exposure to claims by the financiers to these oil trading entities. 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.

How the scope of our audit responded to the key audit matter	**Overall response** We held discussions with management, Deloitte fraud specialists and within the Group engagement team to identify the areas where we felt COVID-19 could have had a potential impact on the financial statements. **Audit procedures in respect of the three principal audit risks identified** Our audit response related to the three principal audit risks identified is set out under the key audit matters for impairment of upstream oil and gas PP&E assets on page 136, the write-off of E&A assets on page 139 and the valuation of other Level 3 instruments on page 140. **Other audit procedures performed** We performed further audit procedures, in addition to those discussed in section 4, to obtain sufficient appropriate audit evidence regarding the appropriateness of management's use of the going concern basis of accounting in the preparation of the financial statements. These procedures included an assessment and reperformance of bp's reverse stress test and a detailed analysis of the new financing agreements. We challenged management's analysis of potential exposures related to bp's decommissioning obligations transferred to third parties as part of disposal transactions, including comparing management's assessment of each counterparty's liquidity and creditworthiness to third party support where available and holding discussions with bp's internal legal counsel. We assessed the credit risk of the portfolio and the associated valuation methodology to check the expected credit loss allowance appropriately reflects the level of risk. In performing this assessment, we considered the impact of demand destruction and price volatility on counterparties in specific market sectors such as Aviation, Independent refiners, Retail Energy Providers, West African oil producers and regional commodity trading organisations. We understood changes made to the control environment following the shift to remote working. Where there was a change in the control, we challenged the appropriateness of these changes and assessed the operating effectiveness of the control in light of these changes. We specifically obtained an understanding of the output of management's review of traders' compliance with policies and procedures in light of remote working, including gain / loss alerts, operational risk incidents reports and internal audit findings. To respond to the oil trading entities' bankruptcies, we altered the nature and extent of our procedures across seaborne trading activity for the year ended 31 December 2020. Using data analytics, we have profiled the related transactions to identify activity that exhibited certain characteristics, such as sale and purchase transactions at the same location with similar settlement dates to determine the validity of such transactions. Our procedures to challenge the validity of the transactions in this population included obtaining an understanding of the commercial rationale for a sample of the contracts, obtaining independent confirmation or sighting third party evidence of bills of lading or other relevant documentation that evidenced the sale of inventory. We read the related disclosures in the Annual Report.
Key observations	Key observations in relation to oil and gas price assumptions used in upstream oil and gas PP&E assets impairment tests, E&A asset write-offs and the valuation of other Level 3 instruments are set out in the relevant key audit matter sections below. We are satisfied with the results of the further audit procedures we performed in respect of going concern and consider that management's conclusion on the going concern assumption remains appropriate as set out in section 4 above. Management's reverse stress test as set out in Note 1 on page 161 indicates that the group will continue to operate as a going concern for at least 12 months from the balance sheet date even if the Brent price fell to zero. In respect of the decommissioning liabilities that transferred to third parties, we agree with management's conclusion that no provision is required based on our assessment of the credit risk. We are satisfied with the disclosure set out in Note 33. We are satisfied with the results of our audit procedures in respect of credit risk and consider that management's expected credit loss valuation methodology and the input assumptions appropriately reflects the level of risk in the current environment. We found that the controls we tested generally operated effectively in the remote working environment and we identified no issues of non-compliance with policies and procedures in the T&S function. Our additional procedures to assess if the Group is exposed to any risk of exposure from finance schemes similar to those that were used by the oil trading entities that declared bankruptcy did not highlight any additional issues. We consider that management's other disclosures in the Annual Report relating to COVID-19 are consistent with the financial statements and our understanding of the business.

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5.2 Potential Impact of climate change and the energy transition (impacting PP&E, goodwill, intangible assets and provisions)	
Key audit matter description	Climate change impacts bp's business in a number of ways as set out in the strategic report on pages 2-70 of the Annual Report and Note 1 on page 160 of the financial statements. It represents a strategic challenge with its implications becoming increasingly significant towards 2050 and beyond. In February 2020 bp announced a new strategic intent which incorporates the ambition to become a 'net zero' company by 2050 or sooner. Further details were announced in August 2020 and September 2020. This led to revised intentions in respect of E&A assets and a significant internal restructuring. In addition, as a consequence of the COVID-19 pandemic, bp revised its oil and gas price forecasts significantly downwards. 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 2050. At current rates of depreciation, depletion and amortisation (DD&A), the average remaining depreciable life of the upstream PP&E is seven years and the downstream PP&E is twelve years. Accordingly, the related principal risks that we have identified for our audit are as follows: • Forecast assumptions used in assessing the value of upstream 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); and • Recoverability of 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 'write-off of exploration and appraisal (E&A) assets' below). Management also assessed the following potential risks that could arise from climate change considerations: • The carrying value of goodwill may no longer be recoverable and therefore may need to be impaired. 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 190-191. The total goodwill balance as at 31 December 2020 is $12.5 billion, of which $7.8 billion relates to the upstream segment. The downstream segment has a goodwill balance of $4.7 billion, of which the most significant element is $2.9 billion relating to the Lubricants business. Notwithstanding the expected global transition to electric vehicles which may reduce demand for Lubricants, management has assessed due to the substantial headroom in the most recent impairment test (as described in Note 14), the likelihood that the recoverable amount of goodwill is less than its carrying value is remote. • Provisions for decommissioning and asset retirement obligations of upstream PP&E may need to be brought forward with a resulting increase in the present value of the associated liabilities. As described in Note 1, the impact of a two-year change to the timing of expected future decommissioning expenditures would not have a material impact on the decommissioning provision reported in the current period; • The carrying value of the downstream PP&E refining assets may no longer be recoverable, due to changes in supply and demand which arise as a consequence of COVID-19, climate change and the energy transition, for example the adoption of electric vehicles in markets where bp has significant fuel refining activity. Management identified impairment indicators at certain of the most material downstream refining assets, as a result of a combination of factors including the onset of COVID-19 and the resulting reduced demand for fuels. Accordingly, impairment tests were performed to assess the recoverability of the refinery asset carrying values. The most significant assumptions in the impairment tests are the assumed future refining margins, and demand profiles for fuel in the markets served by individual refineries. As disclosed in Note 1 to the accounts on page 160, management concluded that no material impairments were required on its downstream assets. • The useful economic lives of the group's downstream refining assets may be shortened as society moves towards 'net zero' emissions targets and bp seeks to achieve its net-zero ambition, such that the depreciation charge is materially understated. As disclosed in Note 1 to the accounts on page 160, management concluded that demand for refined products is expected to remain strong over the useful life of its existing assets and hence no changes to the useful economic lives of its refinery assets was required. • Provisions for decommissioning downstream refining assets, previously not generally recognised on the basis that the potential obligations cannot be measured given their indeterminate settlement dates, might need to be recognised if reductions in demand due to climate change and exacerbated by COVID-19 curtail their operational lives. As disclosed in Note 1 to the accounts on page 171 management concluded that, although obligations may arise if refineries cease manufacturing operations, they would only be recognised at the point when sufficient information became available to determine potential settlement dates. In addition, as noted above, management concluded that demand for refined products is expected to remain strong in areas served by its existing refineries. Accordingly, other than where a decision has been made to cease refining operations, no triggers for assessing the need to record a decommissioning provision have been identified; • Climate change-related litigation brought against bp, as disclosed in Note 33 to the financial statements, may lead to an outflow of funds requiring provision in the current year; and

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	• The announcement of the restructuring of the group and the resulting risk that the costs associated with the restructuring are not appropriately provided for and that following the reduction in size of the workforce the internal controls in place are not appropriately designed, implemented and operating effectively. 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.
How the scope of our audit responded to the key audit matter	**Overall response** We held discussions with management, with Deloitte Climate Change 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. We also established a climate change steering committee comprising a group of senior partners with specific climate change and technical audit and accounting expertise within Deloitte to provide an independent challenge to our key decisions and conclusions with respect to this area. **Audit procedures in respect of the three principal audit risks identified** The audit response related to the two principal audit risks identified is set out under the key audit matters for impairment of upstream oil and gas PP&E assets on page 136-8 and the write-off of exploration and appraisal assets on page 139. **Other audit procedures performed** We performed procedures to satisfy ourselves that, other than future oil and gas price assumptions, there were no other assumptions in management's upstream goodwill impairment test to which reasonably possible changes could cause goodwill to be materially misstated. We obtained evidence which supported management's conclusion that goodwill relating to downstream segment activities is not impaired. We challenged management's assertion that the impact of potential changes to upstream decommissioning dates would not have a material impact on the amounts reported in the current period by assessing the analysis of decommissioning timing, and conducting sensitivity analysis as part of our audit procedures. We challenged the results of the impairment testing of downstream PP&E refining assets by considering internal and external market studies of future supply and demand, and conducting sensitivity analysis. For those refining assets where impairment triggers were identified, we tested the mathematical completeness and accuracy of the impairment models and assessed the appropriateness of key assumptions and inputs. We also tested management's internal controls over the impairment tests. We challenged management's assertion that no changes are required to the assessed useful economic lives of refining assets as a consequence of COVID-19 and climate change factors. In doing this, we obtained third party reports assessing future refined petroleum product demand for those countries which are included in our group full audit scope for downstream. The future demand forecasts were prepared 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'). We challenged management's analysis which supported their judgement that no decommissioning provisions should be recognised in respect of refineries where there is ongoing activity and management has no intention to cease these activities. In doing so we considered the third party forecasts referenced above which, for countries included in our group full audit scope for downstream, show that demand for refined petroleum products is expected to remain significant for at least the current remaining useful economic lives of the refineries, even under scenarios consistent with the Paris 2°C Goal. 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: • 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. We held discussions with management and tested the controls in respect of the restructuring provision. We performed substantive procedures to assess whether the provision was appropriately recognised as required by International Accounting Standard (IAS) 37 'Provisions, Contingent Liabilities and Contingent Assets'. 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.

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Key observations	Key observations in relation to oil and gas price assumptions used in upstream oil and gas PP&E asset 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. We are satisfied with the disclosures around the sensitivity analysis performed in respect of goodwill, and that the significant headroom is indicative that the energy transition and other climate change factors could not lead to a material misstatement of this balance. We are satisfied that the disclosure in Note 1 in respect of the impact of timing on decommissioning provisions is appropriate. We are satisfied with the results of our procedures relating to the carrying value of refining assets and that no impairments are required. Based on the market studies we read, we are satisfied with the results of our procedures relating to the assessment of useful economic lives, and therefore depreciation charges, for downstream refining assets. We noted that the third party demand forecasts generally showed a reduction in forecast long term demand, under a Paris 2°C Goal scenario, compared to the equivalent forecasts in the prior year. Nevertheless, we are satisfied that it is not possible to estimate reliably a settlement date for any decommissioning obligations prior to a decision being made to cease refining operations and that therefore no triggers have arisen that would require a decommissioning provision to be recorded for the group's operating refinery assets. 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 read management's disclosure of the contingent liabilities in respect of these matters and concluded that the disclosures are appropriate. We found the controls relating to the restructuring provision to be operating effectively and are satisfied that the restructuring provision is recorded in accordance with IAS 37, 'Provisions, Contingent Liabilities and Contingent Assets'. 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.

5.3 Impairment of upstream oil and gas PP&E assets

Key audit matter description	The group balance sheet at 31 December 2020 includes PP&E of $115 billion (2019 $133 billion), of which $74 billion (2019 $90 billion) is oil and gas properties within the upstream segment. Management's best estimate of oil and gas price assumptions for value–in-use impairment tests were revised downwards during 2020 compared to the prior year assumptions, as set out in Note 1 on page 161. The downward revisions reflect an expectation that the aftermath of the COVID-19 pandemic will accelerate the pace of transition to a lower carbon economy and energy system. Given the significance of these revisions, management tested all upstream CGUs for impairment. Management recorded $12.9 billion (2019 $6.8 billion) of pre-tax upstream CGU impairment charges, in large part due to the oil and gas prices revisions detailed above, and $0.1 billion of pre-tax upstream CGU impairment reversals (2019 $0.1 billion). Further information has been provided in Note 1 on page 160 and Note 4 on page 179. Through our audit risk assessment procedures, we identified three key management estimates in management's determination of the level of impairment charge and/or reversal to record. These are: • **Oil and gas prices** - bp's oil and gas price assumptions have a significant impact on many CGU impairment assessments performed across the upstream segment, and are inherently uncertain. As noted above, the estimation of future prices is subject to increased uncertainty given climate change, the global energy transition and the impact of COVID-19. There is a risk that management do not forecast reasonable 'best estimate' oil and gas price forecasts when assessing CGUs for impairment, leading to material misstatements. These price assumptions are highly judgmental and are pervasive inputs to most upstream impairment tests, such that any misstatements would also aggregate. • **Discount rates** - Given the long timeframes involved, certain CGU impairment assessments are sensitive to the discount rate applied. Discount rates should reflect the return required by the market and the risks inherent in the cash flows being discounted. There is a risk that management do not assume reasonable discount rates, adjusted as applicable for country risks and relevant tax rates, leading to material misstatements. Determining a reasonable discount rate is highly judgmental and, consistent with price assumptions above, the discount rate assumption is also a pervasive input across upstream impairment tests, before adjustments for asset specific risks and tax rates, such that any misstatements would also aggregate. • **Reserves and resources estimates** - A key input to certain CGU impairment assessments is the oil and gas production forecast, which is based on underlying reserves estimates and field specific development assumptions. Certain CGU production forecasts include specific risk adjusted resource volumes, in addition to proved or probable reserves estimates, that are inherently less certain than reserves; and assumptions related to these volumes can be particularly judgemental. There is a risk that material misstatements could arise from unreasonable production forecasts for individually material CGUs and/or from the aggregation of systematic flaws in bp's reserves and resources estimation policies across the segment.

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	We identified certain individual CGUs with a total carrying value of $32.1 billion (2019 $12.3 billion) which we determined would be most at risk of material impairment charges or reversals as a result of a plausible change in the oil and gas price assumptions. We identified that a subset of these CGUs were also sensitive to the discount rate assumption. Accordingly, we identified these as significant audit risks. We also identified CGUs with a further $16.0 billion (2019 $33.4 billion) of combined 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 or reversal by a plausible change in some or all of the key assumptions. Further information regarding these sensitivities is given in Note 1 on page 167.
How the scope of our audit responded to the key audit matter	We tested management's key internal controls over the estimation of oil and gas prices, discount rates and reserve and resources estimates, as well as key internal controls over the performance of the impairment assessments where we identified audit risks. 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 management's oil and gas price assumptions in order to challenge whether they are reasonable. • In developing this range we obtained a variety of reputable and reliable third party forecasts, peer information and other relevant 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, the energy transition and COVID-19. • We specifically analysed 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 audit evidence. • We challenged management's disclosures in Notes 1 and 4 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, against relevant third party market and peer data. • We assessed whether specific country risks and tax adjustments were reasonably reflected in bp's discount rates. • We challenged management's disclosures in Notes 1 and 4 including in relation to the sensitivity of discount rate assumptions. **Reserves and resources estimates** With the assistance of Deloitte oil and gas reserves specialists we: • assessed bp's reserves and resources estimation methods and policies; • assessed, guided by our risk assessment, how these policies had been applied to a sample of bp's reserves and resources estimates which included those that we judged to represent the greatest risk of material misstatement; • read a sample of reports provided by management's external experts and assessed the scope of work and findings of these third parties; • assessed the competence, capability and objectivity of bp's internal and external reserves experts, through understanding their relevant professional qualifications and experience; • compared the production forecasts used in the impairment tests with management's approved reserves and resources estimates, those estimates having been subjected to the controls that we had tested; and • performed a retrospective assessment to check for indications of estimation bias over time. **Other procedures** • We challenged management's CGU determinations, and considered whether there was any contradictory evidence present. • We validated that bp's impairment methodology was acceptable under IFRS and tested the integrity and mechanical accuracy of certain impairment models based on our risk assessment. • We challenged other CGU specific valuation input assumptions, including but not limited to material cost and tax forecasts, by comparing forecasts to approved internal and third party budgets, development plans, independent expectations and historical actuals. • Where relevant, we assessed management's historical forecasting accuracy and whether the estimates had been determined and applied on a consistent basis across the group.

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Key observations	
	Oil and gas prices We determined that bp’s oil and gas price impairment assumptions are reasonable when compared against a range of third party forecasts that we identified as being appropriate for this purpose, noting in particular that they had been updated for COVID-19. In forming this view, we included each forecaster’s 'base case', 'central case' or 'most likely' estimate. 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. We further observed that, as well as publishing a 'base case', 'central case' or 'most likely' estimate, certain third party price forecasters published other price forecasts including some that were stated as, or were interpreted by us as being, 'Paris 2°C Goal' scenarios. These were typically the lowest of all scenarios from those third parties and we observed that none of those third party forecasters described their 'Paris 2°C Goal' scenarios as their 'base case', 'central case' or 'most likely' estimate. We noted that not all of these third parties had updated their forecasts for COVID-19 although, unlike for the ‘best estimate forecasts’ which had typically been reduced significantly post COVID-19, it is less evident that ‘Paris 2°C forecasts’ would need changing as a result of COVID-19 at least in the longer term and we noted certain updated forecasts that had not changed significantly. Accordingly, in respect of Paris 2°C price scenarios only, we continued to place some weight on certain pre-COVID-19 third party forecasts. Management note on page 160 that they consider their central price assumptions to be broadly in line with a range of transition paths consistent with the goals of the Paris climate change agreement. We observed that for oil, whilst being within the lower half of our range of 'best estimate' forecasts as described above, bp’s price assumptions were overall at the top end of our range of 'Paris 2°C Goal' scenarios. For gas, as well as being within and towards the low end of our range of 'best estimate' forecasts as described above, bp’s price assumptions were within and towards the higher end of our range of 'Paris 2°C Goal' scenarios. We also noted certain other reputable third party sources that set out or implied even higher prices under a Paris 2°C scenario. Accordingly, we consider management’s view as set out above to be reasonable. 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 management’s downside sensitivity, in which oil and gas prices are 10% lower than the best estimate in all future periods, is comfortably within a range of third party Paris 2°C Goal gas price forecasts. For oil, management’s downside sensitivity is comfortably within a range of Paris 2°C Goal forecasts in the period to 2028, but towards the top end of that range by 2050. **Discount rates** bp’s post-tax nominal 6% weighted average cost of capital, being the starting point for setting discount rates used for impairment testing, was within the independent range calculated by our Deloitte valuation specialists. We were also satisfied with the calculation of country risk premia. Accordingly, we are satisfied with the discount rates used in the impairment testing. **Reserves and resources estimates** We found that the production forecasts used in the impairment tests that we tested were reasonable and appropriately risked where applicable, for the purposes of management’s impairment tests.

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5.4 Write-off of E&A assets, included within 'Intangible assets' within the Group balance sheet	
Key audit matter description	The group capitalises E&A expenditure on a project-by-project basis in line with IFRS 6 'Exploration for and Evaluation of Mineral Resources'. At 31 December 2020, $4.1 billion (2019 $14.1 billion) of E&A expenditure was carried on the group balance sheet. E&A activity carries inherent risk and a significant proportion of projects fail, requiring the write-off or impairment of the related capitalised costs when the relevant criteria in IFRS 6 and bp's accounting policy are met. Furthermore, similar to upstream PP&E assets discussed above, E&A assets are also potentially exposed to climate change, the global energy transition, and COVID-19, in that a greater number of E&A projects may not proceed as a consequence of lower forecast future demand and oil and gas pricing, lower appetite by management and the board to allocate capital to certain projects, and/or increased objections from stakeholders to the development of certain projects. As a result of bp's revised strategy announced in 2020, including a reduced capital frame, a net-zero carbon ambition and a decision not to explore in new countries, and reflecting lower oil and gas price assumptions, management identified IFRS 6 impairment indicators at a number of upstream's largest E&A assets during the year. This led to management recording $9.9 billion of pre-tax E&A write-offs and impairments during 2020 (2019 $0.6 billion), detailed further in Notes 1 and 8 on pages 164 and 184. The determination of when E&A costs should be written off or impaired, or retained on the balance sheet as E&A assets, can be complex and require significant judgement from management in assessing this. There is a risk that certain capitalised E&A costs are written off or impaired when they should not have been, due to inappropriate and/or inconsistent application of IFRS 6 impairment criteria and bp's accounting policy, leading to material misstatements. There is also a risk that E&A costs remain capitalised on the balance sheet which ought to have been written off or impaired, leading to material misstatements. We identified significant audit risks for the individually material E&A write-offs and impairments recorded in 2020, specifically the Kaskida and Tigris (Paleogene) licenses that were the largest part of the $2.5 billion Gulf of Mexico write-downs, the Terre de Grace oil sands project that was the largest part of the $2.5 billion Canada write-downs and the BM-C-35, BM-C-32 (Itaipu) & BM-C-30 (Wahoo) licenses that were the largest part of the $2.1 billion Brazil write-downs. We also identified higher risks in relation to certain other 2020 E&A write-offs and impairments recorded; and higher risks at certain assets within the $4.1 billion of E&A costs that remain capitalised under IFRS 6 at 31 December 2020.
How the scope of our audit responded to the key audit matter	We obtained an understanding of the group's E&A assessment processes and tested management's key internal controls. This included the new key internal controls operated by management for the key decisions taken as a result of bp's new strategy, which when taken together with the lower forecast oil and gas prices, led to a large portion of the material write-offs and impairments recorded during 2020. We challenged management's key E&A judgements, with regards to the impairment criteria of IFRS 6 and bp's accounting policy. We corroborated key internal and external evidence relevant to significant write-offs and the assets that remained on the balance sheet. This included analysing evidence of future E&A plans, budgets and capital allocation decisions, assessing management's key accounting judgement papers, holding discussions to challenge top level operational and finance management on the key judgements taken and reading meeting minutes, license documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms, and external press releases. For E&A assets that were written off or impaired by management in 2020, including in particular those based upon decisions taken in line with management's new strategy, we considered whether evidence (and potential contradictory evidence) about activity in the year, future budgeted expenditure and exploration/appraisal plans, including plans and expectations for licence relinquishment or retention, were consistent with the decisions taken by management to write-off or impair these assets. We assessed whether management had consistently applied IFRS 6 and bp's accounting policy to impairment assessments, taking account of in year judgements and historical look back considerations, and the relevant facts and circumstances of specific E&A assets. When considering capital allocation decision making, we considered whether the progression of any projects that remain on the balance sheet would be inconsistent with elements of bp's new strategy and in particular its net zero carbon commitments.
Key observations	We concluded that the key assumptions had been appropriately determined and the judgements management had made were appropriately supported. No inappropriate or untimely E&A impairment charges or write-offs were identified, nor was the need for any additional impairments or write-offs identified from the work we performed. We also confirmed management's view that they did not consider that the progression of any of their E&A assets would be inconsistent with bp's current strategy and management's capital frame and capital allocation intentions.

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5.5 Accounting for structured commodity transactions (SCTs) within the trading and shipping (T&S) function 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)

<table>
<tr><td>Key audit matter description</td><td>
In the normal course of business, T&S enters into a variety of transactions for delivering value across the group’s supply chain. The nature of these transactions requires significant audit effort to be directed towards challenging management’s valuation estimates or the adopted accounting treatment.
We have undertaken an analysis of the portfolio composition and revisited our risk assessment throughout the year focussing particularly on the impact of COVID-19 on the valuation assertion. This process has provided us with a deeper understanding of the impact of market volatility, demand destruction and the changing structure of the markets in which bp operates.
Accounting for structured commodity transactions:
T&S 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 typically complex and involves significant judgment, 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 the classification of liabilities as finance debt. Accordingly, 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. This degree of subjectivity also gives rise to a risk of potential fraud through management incorporating bias in determining fair values. Accordingly, we have identified these as a significant audit risk.
As at 31 December 2020, the group’s total financial assets and liabilities measured at fair value were $12.7 billion (2019 $10.5 billion) and $8.4 billion (2019 $8.8 billion), of which level 3 derivative financial assets were $6.4 billion (2019 $5.5 billion) and level 3 derivative financial liabilities were $5.3 billion (2019 $4.4 billion).
</td></tr>
<tr><td>How the scope of our audit responded to the key audit matter</td><td>
Accounting for SCTs
For structured commodity transactions, we:

Tested controls related to the accounting for complex transactions.
Developed an understanding of the commercial rationale of the transactions through reading transaction documents and executed agreements, and discussions with management.
Performed a detailed accounting analysis for a sample of SCTs involving significant day one profits, deferred working capital arrangements, offtake arrangements and/or commitments. We confirmed that any day one profits were appropriately deferred.

For SCTs which were identified during 2018 and 2019 and that continue through 2020, we have refreshed our assessment in 2020 taking account of any amendments to the contracts.
To assess the appropriateness of the accounting treatment of SCTs, we embedded technical accounting specialists within the audit team.
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 dates, including:

Comparing management’s input assumptions against the expected assumptions of other market participants and observable market data;
Evaluating management’s valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period; and

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	◦ Engaging a Deloitte valuations specialist to challenge models, develop fair value estimates and verify consistency in management's modelling and input assumptions throughout the year. Our independent estimates were established using independently sourced inputs (where available). We evaluated 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 determine whether they were reasonable.
Key observations	We assessed the features of the SCTs and determined that the accounting adopted for each of them was appropriate and in accordance with IFRS. We concluded that management's valuations relating to level 3 instruments were appropriate. We did not identify any indications of inappropriate misrepresentation of revenue recognition in the transactions, valuation estimates or accounting entries that we tested. We did not identify any issues in our testing of the controls related to the accounting for complex transactions and found these to be operating effectively.

5.6 IT controls relating to financial systems (potentially impacting all financial statement accounts)

Key audit matter description	The group's financial systems environment is complex, with 113 separate systems scoped as being relevant for the group audit. Due to the reliance on financial systems within the group, IT controls which support these systems are critical to maintaining an effective control environment. We identified IT control deficiencies in two key areas. **User Access Management:** In 2018 and 2019 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 implemented a remediation and mitigation programme throughout 2019 and 2020, which addresses the vast majority of these user access deficiencies. To the extent the controls were not remediated management designed and tested mitigating controls for the period prior to the successful remediation of each control. The remediation program is substantially complete but will continue into 2021 because certain deficiencies are dependent on other bp change programmes including the completion of a new identity management system implementation. 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, automated controls and reports from the affected systems are not reliable. The access deficiencies impact all components within the scope of our group audit. **Change Management:** We identified in 2019 deficiencies around the bp IT change management process. In 2020, management continued to identify further inconsistent implementation of the minimum change management controls, specifically around approval of changes and evidence of testing. Management has continued to perform retrospective mitigation throughout 2020. Furthermore, in 2020 bp increased its use of the DevOps model for managing change releases. DevOps is an accepted way of managing change which bridges the development and operations process with the aim of reducing change timelines and enabling agility. The implementation of DevOps allows user privileges to be extended so developers are also able to implement changes, a key segregation of duties (SoD) conflict within the change management lifecycle. To manage this key SoD conflict, additional controls need to be implemented to ensure a developer cannot undermine the change management process through the ability to develop and implement the same change. We identified that 25 applications using the DevOps change model did not have appropriate preventative SoD controls in place. For the systems we identified, this issue was remediated and mitigated in 2020 by management. Management has completed a root cause analysis and is implementing a sustainable forward looking governance and control plan to manage the risk around DevOps. 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. The change management issues identified impact all components within the scope of our group audit. Both the user access management controls and the controls over change management 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.

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How the scope of our audit responded to the key audit matter	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. In responding to the identified deficiencies our IT specialists: **User Access Management:** Performed procedures to: • 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. We tested controls implemented by management to identify instances of the use of inappropriate access. **Change Management:** Performed independent testing over: • Mitigating controls identified by management to confirm the integrity of the change management process. These procedures were designed to address the likelihood and impact of inappropriate or untested changes being implemented; and • Management's mitigation procedures, which demonstrated that segregation of duties across the development and implementation of change, for those systems impacted by DevOps was retained. These procedures were designed to address the likelihood and impact that a single user could undermine the bp change management process through creation and implementation of a change.
Key observations	Our testing confirmed that the remediated controls were operating effectively. We also found the mitigating controls management performed to be operating effectively. In addition, 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. 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. Management continues to work to remediate fully the access and change management deficiencies identified.

5.7 Management override of controls (potentially impacting all financial statement accounts)	
Key audit matter description	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: • Inappropriate accounting estimates and judgements; • The posting of fictitious or fraudulent journal entries; or • Accounting for significant unusual transactions arising from changes to the business. 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 as well as other opportunities or incentives which could exist in light of the current environment; During our 2018 and 2019 audits we identified control deficiencies relating to the posting of accounting journal entries at the components where testing was performed. Management's programme to remediate these deficiencies through the design of processes and controls in respect of the posting and review of manual journals was completed by the end of 2020 but has been impacted by the IT Control issues outlined in section 5.6 above. Accordingly, these control deficiencies remained during 2020 and we tested the mitigating controls which had been identified by management during the previous years' audits or other appropriate controls to mitigate these deficiencies. We expect to be testing the remediated journal controls in 2021 once the related IT control deficiencies have been remediated. This had a significant bearing again this year on the allocation of audit resources and has been discussed with the audit committee throughout the year. Accordingly, we identified this as a key audit matter.

How the scope of our audit responded to the key audit matter	We tested the mitigating controls that management identified as responding to the risk of fraudulent journal entries. In addition, we: • 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 associated with common fraud schemes for testing. • Tested journal entries and other adjustments recorded in the general ledger throughout the period, with a particular focus on adjustments that occur late in the financial close process. We have assessed accounting estimates for bias and evaluated whether the circumstances producing the bias, if any, represent a risk of material misstatement due to fraud. A number of the most significant estimates are covered by the other Key Audit Matters set out above. This assessment included: • Evaluating whether the judgements and decisions made by management in making the accounting estimates included in the financial statements, even if they are individually reasonable, indicate a possible bias on the part of bp's management that may represent a risk of material misstatement due to fraud; and • Performing a retrospective analysis of management judgements and assumptions related to significant accounting estimates reflected in the financial statements of the prior year. We considered whether there were any significant transactions that are outside the normal course of business, or that otherwise appear to be unusual due to their nature, timing or size. The risks and responses to the revenue recognition risks within the trading and shipping function are set out on pages 140-141.
Key observations	Mitigating controls to address the risk associated with the design deficiencies were 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 controls concluded they were, in combination, appropriately designed and implemented and they were operating effectively for the year. Our substantive testing of journal entries and other adjustments, selected through the use of our data analytics tools, did not identify any inappropriate items. We did not identify evidence of overall bias or any significant unusual transactions for which the business rationale (or the lack thereof) of the transaction suggested that it may have been entered into to engage in fraudulent financial reporting or to conceal misappropriation of assets. Management expects the journal control remediation programme to be completed in 2021.

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6. Our application of materiality

6.1 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 $600 million for the current year. In 2019, we used a materiality of $850 million. The decrease is due to bp's financial performance in 2020.	Materiality has been set at $900 million for the current year (2019 $1,200 million).
Basis for determining materiality	Due to the significant losses incurred in 2020 as a consequence, inter alia, of the COVID-19 pandemic and in particular the decrease in oil and gas prices, we have changed our chosen metric from profit before tax in 2019 to net assets in 2020. We concluded that loss measures are not appropriate in our determination of materiality. Materiality was determined to be $600 million, which is 0.73% of net assets. In 2019, we determined materiality to be $850 million, which represented 10.3% of profit before taxation, 5% of underlying replacement cost profit before interest and taxation and 0.84% of net assets. Recognising the change in environment and using our professional judgement we have opted to use a conservative (lower) % of net assets given the uncertainty as to the level of future results.	We determined materiality for our audit of the standalone parent using 1% (2019 1%) of net assets.
Rationale for the benchmark applied	We conducted an assessment of which line items are the most important to investors and analysts by reading analyst reports and bp's communications to shareholders and lenders, as well as the communications of peer companies. We then considered the fact that bp reported a loss during the year. This resulted in us selecting net assets as the most appropriate benchmark. 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. As noted above, the COVID-19 pandemic and in particular the decrease in oil and gas prices resulted in significant losses in 2020. We therefore placed our emphasis on net assets in our determination of materiality this year. We further note that the non-GAAP measure underlying replacement cost profit before interest and tax is one of the key metrics communicated by management in bp's results announcements. Although it excludes some of the volatility arising from changes in crude oil, gas and product prices as well as 'non-operating items', the significant decrease in oil and gas prices was such that this measure was also a loss, and therefore we concluded this was not an appropriate metric on which to determine materiality this year.	The materiality determined for the standalone parent company financial statements exceeds the group materiality. This is due to the fact that the net asset balance of the parent company financial statements exceeds the net asset balance of the group financial statements. As the company is non-trading and operates primarily as a holding company, we believe the net asset position is the most appropriate benchmark to use. Where there were balances and transactions within the parent company accounts that were within the scope of the audit of the group financial statements, our procedures were undertaken using the lower materiality level applicable 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.

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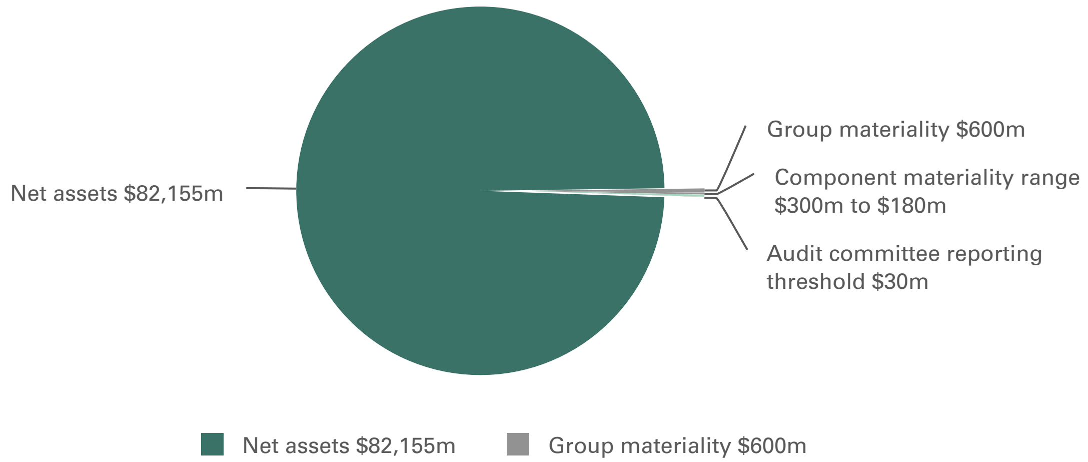

6.2 Performance materiality

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 2020 audit (2019 60%) and parent company performance materiality was set at 60% of parent company materiality for the 2020 audit (2019 60%).

Given the significant changes in the business environment due to the COVID-19 pandemic, we maintained a percentage consistent with that of our 2019 audit rather than increasing it to reflect the quality of the control environment and the fact that we are generally able to rely on controls, the relatively low level of misstatements identified in the current and prior years, as well as the fact that management is generally willing to correct these misstatements.

6.3 Error reporting threshold

We agreed with the audit committee that we would report to the committee all audit differences in excess of $30 million (2019 $35 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.

7. An overview of the scope of our audit

7.1 Identification and scoping of components

As a result of the highly disaggregated nature of the group, with operations in over 70 countries through approximately 920 cons units, 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 cons units that are in scope for group reporting purposes, included the following:

- The financial significance of an operating unit (which will typically include multiple cons units) to bp's revenue and loss 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 2019 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 173 reporting cons units (2019 179) which were selected based on their size or risk characteristics. The primary reason for the change in scope is due to certain cons units in the T&S function no longer being used by management to record transactions. Our full-scope audits are in the UK, US, Azerbaijan, Germany, Canada 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 in 62 cons units (2019 55) also covering operations in Angola, Alaska, Trinidad & Tobago, Mauritania & Senegal, and Australia. The group engagement team performed audit procedures on specified account balances to component materiality, with certain additional specific procedures performed by component teams, covering an additional 42 cons units (2019 29).

The remaining cons units are not significant individually and include many small, low risk components and balances. On average, they each represent 0.03% of group revenue (2019 0.03%) and 0.03% of property, plant and equipment (2019 0.03%).

In our assessment of the residual balances not covered by the above procedures, 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 also tested management's group-wide controls across a range of locations and segments. We concluded that through this additional risk assessment, we have reduced the audit risk of such a misstatement arising to a sufficiently low level.

Our audit coverage of ‘Property, plant and equipment’ and ‘Sales and other operating revenue’ is materially the same as in the prior year.

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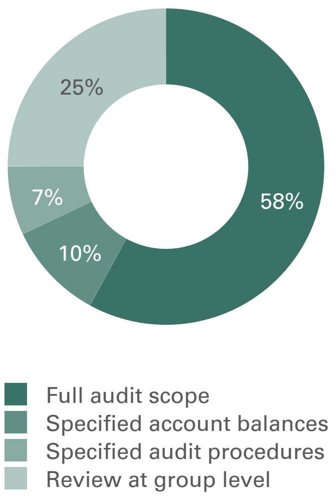
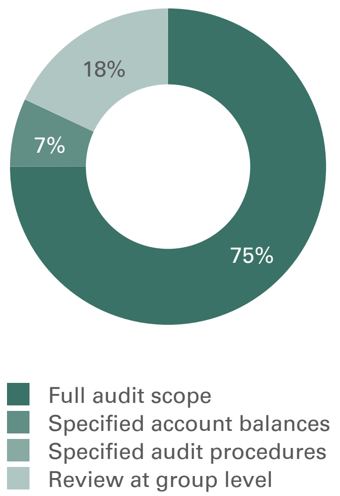
Property, plant and equipment



Sales and other operating revenues



7.2 Our consideration of the control environment

Our audit approach was generally to place reliance on management's relevant controls over all business cycles affecting in scope financial statement line items. As part of our controls testing, we assessed the design and implementation of controls and tested a sample for operating effectiveness through a combination of tests of inquiry, observation, inspection and re-performance.

In limited situations where we were not able to take a controls reliance approach due to controls being deficient and there not being sufficient mitigating or alternative controls we could rely on instead, we adopted a non-controls reliance approach. All control deficiencies which we considered to be significant, including those in respect of management override (see above) were communicated to the audit committee. All other deficiencies were communicated to management. For all deficiencies identified we considered the impact and updated our audit plan accordingly.

The group's financial systems environment is complex, with 113 separate IT systems scoped as being relevant to the audit for the following key locations (UK, US, Germany, Angola, Azerbaijan and Australia) as well as other minor locations. These systems are all directly or indirectly relevant to the entity's financial reporting process.

We planned to rely on the General IT Controls (GITCs) associated with these systems, where the GITCs were appropriately designed and implemented, and these were operating effectively. To assess the operating effectiveness of GITCs we performed testing on access security, change management, data centre operations and network operations. We have included our observations on the IT controls in our key audit matter section, (see 'IT controls relating to financial systems' above).

7.3 Working with other auditors

The group audit team are responsible for the scope and direction of the audit process and provide direct oversight, review, and coordination of our component audit teams. We interacted regularly with the component Deloitte teams during each stage of the audit 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.

Due to the COVID-19 pandemic and the travel restrictions in place during the year, the senior statutory auditor and other group audit partners were unable to conduct visits to meet with the component teams responsible for the full scope locations, and other key locations including the key Global Business Services (GBS) accounting locations. As a result of this, we performed alternative virtual procedures which 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 virtually 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.

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8. 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.

We have nothing to report in respect of these matters.

9. 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.

10. 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.

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.

11. 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.

11.1 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 frameworks 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.

11.2 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

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within T&S, 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 in-house / 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 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

12. 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.

13. Corporate Governance Statement

The Listing Rules require us to review the directors' statement in relation to going concern, longer-term viability and that part of the Corporate Governance Statement relating to the group's compliance with the provisions of the UK Corporate Governance Code specified for our review.

Based on the work undertaken as part of our audit, we have concluded that each of the following elements of the Corporate Governance Statement is materially consistent with the financial statements and our knowledge obtained during the audit:

- the directors' statement with regards to the appropriateness of adopting the going concern basis of accounting and any material uncertainties identified set out on page 128;
- the directors' explanation as to its assessment of the group's prospects, the period this assessment covers and why the period is appropriate set out on page 128;
- the directors' statement on fair, balanced and understandable set out on page 127;
- the board's confirmation that it has carried out a robust assessment of the emerging and principal risks set out on pages 81;
- the section of the annual report that describes the review of effectiveness of risk management and internal control systems set out on page 127; and
- the section describing the work of the audit committee set out on pages 94-99.

14. Matters on which we are required to report by exception

14.1 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.

14.2 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.

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

15. Other matters

15.1 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 27 May 2020, 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 2021 and authorized the directors to set the audit fees.

The first accounting period we audited was the 12 month period ended 31 December 2018. The period of total uninterrupted engagement including previous renewals and reappointments of the firm is 3 years, covering the years ending 31 December 2018 to 31 December 2020.

15.2 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).

16. 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
22 March 2021

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

Consolidated financial statements of the bp group

Report of Independent Registered Public Accounting Firm

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

Opinion on the financial statements

We have audited the accompanying consolidated group balance sheets of BP p.l.c. and subsidiaries (together the company) as of 31 December 2020 and 2019, 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 three years in the period ended 31 December 2020, and the related notes (collectively referred to as the 'financial statements'). In our opinion, the financial statements present fairly, in all material respects, the financial position of the company as of 31 December 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended 31 December 2020, in conformity with International Financial Reporting Standards (IFRS) as adopted by the European Union and IFRS as issued by the International Accounting Standards Board.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the company's internal control over financial reporting as of 31 December 2020, 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 22 March 2021 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 audits provide 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 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 financial statements and (2) involved our 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.

1. Property, plant and equipment (PP&E) assets – Impairment of upstream oil and gas – Notes 1, 4 and 12 to the financial statements

Critical Audit Matter Description

The group balance sheet at 31 December 2020 includes PP&E of $115 billion, of which $74 billion is oil and gas properties within the upstream segment.

Management's best estimate of oil and gas price assumptions for value–in-use impairment tests were revised downwards during 2020 compared to the prior year assumptions, as set out in Note 1 on page 161. The downward revisions reflect an expectation that the aftermath of the COVID-19 pandemic will accelerate the pace of transition to a lower carbon economy and energy system. Given the significance of these revisions, management tested all upstream CGUs for impairment.

Management recorded $12.9 billion of pre-tax upstream CGU impairment charges, in large part due to the oil and gas prices revisions detailed above, and $0.1 billion of pre-tax upstream CGU impairment reversals. Further information has been provided in Note 1 on page 160, Note 4 on page 179 and Note 12 on page 189.

Through our audit risk assessment procedures, we have a identified a critical audit matter in respect of PP&E impairment principally due to the following three key management estimates in management's determination of the level of impairment charge and/or reversal to record.

- **Oil and gas prices** - bp's oil and gas price assumptions have a significant impact on many CGU impairment assessments performed across the upstream segment, and are inherently uncertain. As noted above, the estimation of future prices is subject to increased uncertainty given climate change, the global energy transition and the impact of COVID-19. There is a risk that management do not forecast reasonable "best estimate" oil and gas price forecasts when assessing CGUs for impairment, leading to material misstatements. These price assumptions are highly judgmental and are pervasive inputs to most upstream impairment tests, such that any misstatements would also aggregate. There is also a risk that management's oil and gas price related disclosures are not reasonable.
- **Discount rates** - Given the long timeframes involved, certain CGU impairment assessments are sensitive to the discount rate applied. Discount rates should reflect the return required by the market and the risks inherent in the cash flows being discounted. There is a risk that management do not assume reasonable discount rates, adjusted as applicable for country risks and relevant tax rates, leading to material misstatements. Determining a reasonable discount rate is highly judgmental and, consistent with price assumptions above, the discount rate assumption is also a pervasive input across upstream impairment tests, before adjustments for asset specific risks and tax rates, such that any misstatements would also aggregate.
- **Reserves and resources estimates** - A key input to certain CGU impairment assessments is the oil and gas production forecast, which is based on underlying reserves estimates and field specific development assumptions. Certain CGU production forecasts include specific risk adjusted resource volumes, in addition to proved or probable reserves estimates, that are inherently less certain than reserves; and assumptions related to these volumes can be particularly judgemental. There is a risk that material misstatements could arise from unreasonable production forecasts for individually material CGUs and/or from the aggregation of systematic flaws in bp's reserves and resources estimation policies across the segment.

We identified certain individual CGUs with a total carrying value of $32.1 billion which we determined would be most at risk of material impairment charges or reversals as a result of a plausible change in the key assumptions, particularly oil and gas price and discount rate assumptions.

We also identified CGUs with a further $16.0 billion of combined carrying value which were less sensitive as they would be potentially at risk, in aggregate, to a material impairment or reversal by a plausible change in some or all of the key assumptions.

Further information regarding these sensitivities is given in Note 1 on page 167.

How the Critical Audit Matter was addressed in the Audit

We tested management's key internal controls over the estimation of oil and gas prices, discount rates and reserve and resources estimates, as well as key internal controls over the performance of the impairment assessments where we identified audit risks. 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 management's oil and gas price assumptions in order to challenge whether they are reasonable.
- In developing this range we obtained a variety of reputable and reliable third party forecasts, peer information and other relevant 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, the energy transition and COVID-19.
- We specifically analysed 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 audit evidence.
- We challenged management's disclosures in Notes 1 and 4 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, against relevant third party market and peer data.
- We assessed whether specific country risks and tax adjustments were reasonably reflected in bp's discount rates.
- We challenged management's disclosures in Notes 1 and 4 including in relation to the sensitivity of discount rate assumptions.

Reserves and resources estimates

With the assistance of Deloitte oil and gas reserves specialists we:

- assessed bp's reserves and resources estimation methods and policies;
- assessed, guided by our risk assessment, how these policies had been applied to a sample of bp's reserves and resources estimates which included those that we judged to represent the greatest risk of material misstatement;
- read a sample of reports provided by management's external reserves experts and assessed the scope of work and findings of these third parties;
- assessed the competence, capability and objectivity of bp's internal and external reserve experts; through understanding their relevant professional qualifications and experience.
- compared the production forecasts used in the impairment tests with management's approved reserves and resources estimates, those estimates having been subjected to the controls that we had tested; and
- performed a retrospective assessment to check for indications of estimation bias over time

Other procedures

- We challenged management's CGU determinations, and considered whether there was any contradictory evidence present.
- We validated that bp's impairment methodology was acceptable under IFRS and tested the integrity and mechanical accuracy of certain impairment models based on our risk assessment.
- We challenged other CGU specific valuation input assumptions, including but not limited to material cost and tax forecasts, by comparing forecasts to approved internal and third party budgets, development plans, independent expectations and historical actuals.
- Where relevant, we assessed management's historical forecasting accuracy and whether the estimates had been determined and applied on a consistent basis across the group.

2. Intangible assets – Write-off of Exploration and Appraisal (E&A) assets, included within 'intangible assets' within the Group balance sheet – Notes 1, 8 and 15 to the financial statements

Critical Audit Matter Description

The group capitalises E&A expenditure on a project-by-project basis in line with IFRS 6 'Exploration for and Evaluation of Mineral Resources'. At 31 December 2020, $4.1 billion of E&A expenditure was carried on the group balance sheet.

E&A activity carries inherent risk and a significant proportion of projects fail, requiring the write-off or impairment of the related capitalised costs when the relevant criteria in IFRS 6 and bp's accounting policy are met.

Furthermore, similar to upstream PP&E assets discussed above, E&A assets are also potentially exposed to climate change, the global energy transition, and COVID-19, in that a greater number of E&A projects may not proceed as a consequence of lower forecast future demand and oil and gas pricing, lower appetite by management and the board to allocate capital to certain projects, and/or increased objections from stakeholders to the development of certain projects.

As a result of bp's revised strategy announced in 2020, including a reduced capital frame, a net-zero carbon ambition and a decision not to explore in new countries, and reflecting lower oil and gas price assumptions, management identified IFRS 6 impairment indicators at a number of upstream's largest E&A assets during the year. This led to management recording $9.9 billion of pre-tax E&A write-offs and impairments during 2020, detailed further in Notes 1 and 8 on pages 164 and 184.

The determination of when E&A costs should be written off or impaired, or retained on the balance sheet as E&A assets, can be complex and require significant judgement from management in assessing this. There is a risk that certain capitalised E&A costs are written off or impaired when they should not have been, due to inappropriate and/or inconsistent application of IFRS 6 impairment criteria and bp's accounting policy, leading to material misstatements. There is also a risk that E&A costs remain capitalised on the balance sheet which ought to have been written off or impaired, leading to material misstatements.

We identified a critical audit matter for the individually material E&A write-offs recorded in 2020, specifically the Kaskida and Tigris (Paleogene) licenses that were the largest part of the $2.5 billion Gulf of Mexico write downs, the Terre de Grace oil sands project that was the largest part of the $2.5 billion Canada write downs and the three licenses that were the largest part of the $2.1 billion Brazil write-downs. We also identified higher risks in relation to certain other 2020 E&A write-offs and impairments recorded; and higher risks at certain assets within the $4.4 billion of E&A costs that remain capitalised under IFRS 6 at 31 December 2020.

How the Critical Audit Matter was addressed in the Audit

We obtained an understanding of the group's E&A assessment processes and tested management's key internal controls. This included the key internal controls operated by management for the key decisions taken as a result of bp's new strategy, which when taken together with the lower forecast oil and gas prices, led to a large portion of the material write-offs and impairments recorded during 2020.

We challenged management's key E&A judgements, with regards to the impairment criteria of IFRS 6 and bp's accounting policy. We corroborated key internal and external evidence relevant to significant write-offs and the assets that remained on the balance sheet. This included analysing evidence of future E&A plans, budgets and capital allocation decisions, assessing management's key accounting judgement papers, holding discussions to challenge top level operational and finance management on the key judgements taken and reading meeting minutes, license documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms, and external press releases.

For E&A assets that were written off or impaired by management in 2020, including in particular those based upon decisions taken in line with management's new strategy, we considered whether evidence (and potential contradictory evidence) about activity in the year, future budgeted expenditure and exploration/appraisal plans, including plans and expectations for licence relinquishment or retention, were consistent with the decisions taken by management to write-off or impair these assets.

We assessed whether management had consistently applied IFRS 6 and bp's accounting policy to impairment assessments, taking account of in year judgements and historical look back considerations, and the relevant facts and circumstances of specific E&A assets.

When considering capital allocation decision making, we considered whether the progression of any projects that remain on the balance sheet would be inconsistent with elements of bp's new strategy and in particular its net zero carbon commitments.

3. Accounting for structured commodity transactions (SCTs) within the trading and shipping (T&S) function 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, T&S enters into a variety of transactions for delivering value across the group's supply chain. The nature of these transactions requires significant audit effort to be directed towards challenging management's valuation estimates or the adopted accounting treatment.

We have undertaken an analysis of the portfolio composition and revisited our risk assessment throughout the year focussing particularly on the impact of COVID-19 on the valuation assertion. This process has provided us with a deeper understanding of the impact of market volatility, demand destruction and the changing structure of the markets in which bp operates.

Accounting for structured commodity transactions:
T&S 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 typically complex and involves significant judgment, 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 the classification of liabilities as finance debt. Accordingly, we have identified the accounting for SCTs as a critical audit matter.

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. This degree of subjectivity also gives rise to a risk of potential fraud through management incorporating bias in determining fair values. Accordingly, we have identified these as a significant audit risk.

As at 31 December 2020, the group's total financial assets and liabilities measured at fair value were $12.7 billion and $8.4 billion, of which level 3 derivative financial assets were $6.4 billion and level 3 derivative financial liabilities were $5.3 billion.

How the Critical Audit Matter was addressed in the Audit

Accounting for SCTs
For structured commodity transactions, we:

- Tested controls related to the accounting for complex transactions.
- Developed an understanding of the commercial rationale of the transactions through reading transaction documents and executed agreements, and discussions with management.
- Performed a detailed accounting analysis for a sample of SCTs involving significant day one profits, deferred working capital arrangements, offtake arrangements and/or commitments. We confirmed that any day one profits were appropriately deferred.

For SCTs which were identified during 2018 and 2019 and that continue through 2020, we have refreshed our assessment in 2020 taking account of any amendments to the contracts.

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

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:
  - Comparing management's input assumptions against the expected assumptions of other market participants and observable market data;
  - Evaluating management's valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period; and
  - Engaging a Deloitte valuations specialist to challenge models, develop fair value estimates and verify consistency in management's modelling and input assumptions throughout the year. Our independent estimates were established using independently sourced inputs (where available). We evaluated 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 determine whether they were reasonable.

/s/ Deloitte LLP

London
United Kingdom
22 March 2021

The first accounting period we audited was the 12 month period ended 31 December 2018.

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 2020, 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 at 31 December 2020, 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 2020, of the Company and our report dated 22 March 2021, expressed an unqualified opinion on those consolidated 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
22 March 2021

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	**2020**	2019	2018
Sales and other operating revenues	6	**180,366**	278,397	298,756
Earnings from joint ventures – after interest and tax	16	**(302)**	576	897
Earnings from associates – after interest and tax	17	**(101)**	2,681	2,856
Interest and other income	7	**663**	769	773
Gains on sale of businesses and fixed assets	4	**2,874**	193	456
Total revenues and other income		**183,500**	282,616	303,738
Purchases	19	**132,104**	209,672	229,878
Production and manufacturing expenses		**22,494**	21,815	23,005
Production and similar taxes	5	**695**	1,547	1,536
Depreciation, depletion and amortization	5	**14,889**	17,780	15,457
Impairment and losses on sale of businesses and fixed assets	4	**14,381**	8,075	860
Exploration expense	8	**10,280**	964	1,445
Distribution and administration expenses		**10,397**	11,057	12,179
Profit (loss) before interest and taxation		**(21,740)**	11,706	19,378
Finance costs	7	**3,115**	3,489	2,528
Net finance expense relating to pensions and other post-retirement benefits	24	**33**	63	127
Profit (loss) before taxation		**(24,888)**	8,154	16,723
Taxation	9	**(4,159)**	3,964	7,145
Profit (loss) for the year		**(20,729)**	4,190	9,578
Attributable to				
bp shareholders		**(20,305)**	4,026	9,383
Non-controlling interests		**(424)**	164	195
		(20,729)	4,190	9,578
Earnings per share				
Profit (loss) for the year attributable to bp shareholders				
Per ordinary share (cents)				
Basic	11	**(100.42)**	19.84	46.98
Diluted	11	**(100.42)**	19.73	46.67
Per ADS (dollars)				
Basic	11	**(6.03)**	1.19	2.82
Diluted	11	**(6.03)**	1.18	2.80

Group statement of comprehensive income[a]

For the year ended 31 December				$ million
	Note	2020	2019	2018
Profit (loss) for the year		**(20,729)**	4,190	9,578
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**(1,843)**	1,538	(3,771)
Exchange (gains) losses on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**(353)**	880	—
Cash flow hedges marked to market	30	**78**	(100)	(126)
Cash flow hedges reclassified to the income statement	30	**(37)**	106	120
Costs of hedging marked to market	30	**42**	(4)	(244)
Costs of hedging reclassified to the income statement	30	**22**	57	58
Share of items relating to equity-accounted entities, net of tax	16, 17	**312**	82	417
Income tax relating to items that may be reclassified	9	**66**	(70)	4
		(1,713)	2,489	(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	24	**170**	328	2,317
Cash flow hedges that will subsequently be transferred to the balance sheet	30	**7**	(3)	(37)
Income tax relating to items that will not be reclassified	9	**(105)**	(157)	(718)
		72	168	1,562
Other comprehensive income		**(1,641)**	2,657	(1,980)
Total comprehensive income		**(22,370)**	6,847	7,598
Attributable to				
bp shareholders		**(21,983)**	6,674	7,444
Non-controlling interests		**(387)**	173	154
		(22,370)	6,847	7,598

[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 Hybrid bonds	Non-controlling interests Other interest	Total equity
At 1 January 2020	**46,525**	**(14,412)**	**(6,495)**	**(912)**	**73,706**	**98,412**	**—**	**2,296**	**100,708**
Profit for the year	**—**	**—**	**—**	**—**	**(20,305)**	**(20,305)**	**256**	**(680)**	**(20,729)**
Other comprehensive income	**—**	**—**	**(2,224)**	**98**	**448**	**(1,678)**	**—**	**37**	**(1,641)**
Total comprehensive income	**—**	**—**	**(2,224)**	**98**	**(19,857)**	**(21,983)**	**256**	**(643)**	**(22,370)**
Dividends[b]	**—**	**—**	**—**	**—**	**(6,367)**	**(6,367)**	**—**	**(238)**	**(6,605)**
Cash flow hedges transferred to the balance sheet, net of tax	**—**	**—**	**—**	**6**	**—**	**6**	**—**	**—**	**6**
Repurchase of ordinary share capital	**—**	**—**	**—**	**—**	**(776)**	**(776)**	**—**	**—**	**(776)**
Share-based payments, net of tax	**176**	**1,188**	**—**	**—**	**(638)**	**726**	**—**	**—**	**726**
Share of equity-accounted entities' changes in equity, net of tax	**—**	**—**	**—**	**—**	**1,341**	**1,341**	**—**	**—**	**1,341**
Issue of perpetual hybrid bonds	**—**	**—**	**—**	**—**	**(48)**	**(48)**	**11,909**	**—**	**11,861**
Payments on perpetual hybrid bonds	**—**	**—**	**—**	**—**	**—**	**—**	**(89)**	**—**	**(89)**
Tax on issue of perpetual hybrid bonds	**—**	**—**	**—**	**—**	**3**	**3**	**—**	**—**	**3**
Transactions involving non-controlling interests, net of tax	**—**	**—**	**—**	**—**	**(64)**	**(64)**	**—**	**827**	**763**
At 31 December 2020	**46,701**	**(13,224)**	**(8,719)**	**(808)**	**47,300**	**71,250**	**12,076**	**2,242**	**85,568**
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

[a] See Note 32 for further information.
[b] See Note 10 for further information.

Group balance sheet

At 31 December			$ million
	Note	2020	2019
Non-current assets			
Property, plant and equipment	12	**114,836**	132,642
Goodwill	14	**12,480**	11,868
Intangible assets	15	**6,093**	15,539
Investments in joint ventures	16	**8,362**	9,991
Investments in associates	17	**18,975**	20,334
Other investments	18	**2,746**	1,276
Fixed assets		**163,492**	191,650
Loans		**840**	630
Trade and other receivables	20	**4,351**	2,147
Derivative financial instruments	30	**9,755**	6,314
Prepayments		**533**	781
Deferred tax assets	9	**7,744**	4,560
Defined benefit pension plan surpluses	24	**7,957**	7,053
		194,672	213,135
Current assets			
Loans		**458**	339
Inventories	19	**16,873**	20,880
Trade and other receivables	20	**17,948**	24,442
Derivative financial instruments	30	**2,992**	4,153
Prepayments		**1,269**	857
Current tax receivable		**672**	1,282
Other investments	18	**333**	169
Cash and cash equivalents	25	**31,111**	22,472
		71,656	74,594
Assets classified as held for sale	2	**1,326**	7,465
		72,982	82,059
Total assets		**267,654**	295,194
Current liabilities			
Trade and other payables	22	**36,014**	46,829
Derivative financial instruments	30	**2,998**	3,261
Accruals		**4,650**	5,066
Lease liabilities	28	**1,933**	2,067
Finance debt	26	**9,359**	10,487
Current tax payable		**1,038**	2,039
Provisions	23	**3,761**	2,453
		59,753	72,202
Liabilities directly associated with assets classified as held for sale	2	**46**	1,393
		59,799	73,595
Non-current liabilities			
Other payables	22	**12,112**	12,626
Derivative financial instruments	30	**5,404**	5,537
Accruals		**852**	996
Lease liabilities	28	**7,329**	7,655
Finance debt	26	**63,305**	57,237
Deferred tax liabilities	9	**6,831**	9,750
Provisions	23	**17,200**	18,498
Defined benefit pension plan and other post-retirement benefit plan deficits	24	**9,254**	8,592
		122,287	120,891
Total liabilities		**182,086**	194,486
Net assets		**85,568**	100,708
Equity			
bp shareholders' equity	32	**71,250**	98,412
Non-controlling interests	32	**14,318**	2,296
Total equity	32	**85,568**	100,708

Helge Lund Chairman
Bernard Looney Chief executive officer
22 March 2021

Group cash flow statement

For the year ended 31 December				$ million
	Note	2020	2019	2018
Operating activities				
Profit (loss) before taxation		**(24,888)**	8,154	16,723
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	8	**9,920**	631	1,085
Depreciation, depletion and amortization	5	**14,889**	17,780	15,457
Impairment and (gain) loss on sale of businesses and fixed assets	4	**11,507**	7,882	404
Earnings from joint ventures and associates		**403**	(3,257)	(3,753)
Dividends received from joint ventures and associates		**1,442**	1,962	1,535
Interest receivable		**(258)**	(441)	(468)
Interest received		**74**	416	348
Finance costs	7	**3,115**	3,489	2,528
Interest paid		**(2,728)**	(2,870)	(1,928)
Net finance expense relating to pensions and other post-retirement benefits	24	**33**	63	127
Share-based payments		**723**	730	690
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	24	**(282)**	(238)	(386)
Net charge for provisions, less payments		**735**	(176)	986
(Increase) decrease in inventories		**3,963**	(3,406)	672
(Increase) decrease in other current and non-current assets		**4,230**	(2,335)	(2,858)
Increase (decrease) in other current and non-current liabilities		**(8,278)**	2,823	(2,577)
Income taxes paid		**(2,438)**	(5,437)	(5,712)
Net cash provided by operating activities		**12,162**	25,770	22,873
Investing activities				
Expenditure on property, plant and equipment, intangible and other assets		**(12,306)**	(15,418)	(16,707)
Acquisitions, net of cash acquired	3	**(44)**	(3,562)	(6,986)
Investment in joint ventures		**(567)**	(137)	(382)
Investment in associates		**(1,138)**	(304)	(1,013)
Total cash capital expenditure		**(14,055)**	(19,421)	(25,088)
Proceeds from disposals of fixed assets	4	**491**	500	940
Proceeds from disposals of businesses, net of cash disposed	4	**4,989**	1,701	1,911
Proceeds from loan repayments		**717**	246	666
Net cash used in investing activities		**(7,858)**	(16,974)	(21,571)
Financing activities				
Repurchase of shares		**(776)**	(1,511)	(355)
Lease liability payments		**(2,442)**	(2,372)	(35)
Proceeds from long-term financing		**14,736**	8,597	9,038
Repayments of long-term financing		**(12,179)**	(7,118)	(7,175)
Net increase (decrease) in short-term debt		**(1,234)**	180	1,317
Issue of perpetual hybrid bonds		**11,861**	—	—
Payments on perpetual hybrid bonds		**(89)**	—	—
Payments relating to transactions involving non-controlling interests (other)		**(8)**	—	—
Receipts relating to transactions involving non-controlling interests (other)		**665**	566	—
Dividends paid				
bp shareholders	10	**(6,340)**	(6,946)	(6,699)
Non-controlling interests		**(238)**	(213)	(170)
Net cash provided by (used in) financing activities		**3,956**	(8,817)	(4,079)
Currency translation differences relating to cash and cash equivalents		**379**	25	(330)
Increase (decrease) in cash and cash equivalents		**8,639**	4	(3,107)
Cash and cash equivalents at beginning of year		**22,472**	22,468	25,575
Cash and cash equivalents at end of year		**31,111**	22,472	22,468

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 2020 were approved and signed by the chief executive officer and chairman on 22 March 2021 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 adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the European Union (EU) and in accordance with the provisions of the UK Companies Act 2006 as applicable to companies reporting under international accounting standards. 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. As a result of the UK's withdrawal from the EU, with effect for periods starting subsequent to the year ended 31 December 2020, the consolidated financial statements will also be prepared in accordance with UK-adopted international accounting standards. There were no differences between IFRS as adopted by the EU and UK-adopted international accounting standards as at 1 January 2021. The UK's withdrawal from the EU has not had and is not expected to have a significant impact on the consolidated financial statements. 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 2020. 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; supplier financing arrangements; derivative financial instruments; provisions and contingencies; and pensions and other post-retirement benefits. Judgements and estimates, not all of which are significant, made in assessing the impact of the COVID-19 pandemic, and climate change and the transition to a lower carbon economy on the consolidated financial statements are also set out in boxed text below. 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.

Judgements and estimates made in assessing the impact of climate change and the transition to a lower carbon economy

Climate change and the transition to a lower carbon economy were considered in preparing the consolidated financial statements. These may have significant impacts on the currently reported amounts of the group's assets and liabilities discussed below and on similar assets and liabilities that may be recognized in the future.

Impairment of property, plant and equipment, and goodwill

The energy transition is likely to impact the future prices of commodities such as oil and natural gas which in turn may affect the recoverable amount of property, plant and equipment, and goodwill in the oil and gas industry. Management's best estimate of oil and natural gas price assumptions for value-in-use impairment testing were revised downwards during 2020 and the period covered extended to 2050. The revised assumptions sit within the range of external forecasts considered by management and are broadly in line with a range of transition paths consistent with the goals of the Paris climate change agreement. See significant judgements and estimates: recoverability of asset carrying values for further information including sensitivity analysis in relation to reasonably possible changes in the price assumptions.

Impairments were recognized during 2020 on certain Upstream oil and gas properties as a result of the lower price assumptions. See note 4 for further information.

No material impairments were recognized on Downstream assets. Though the energy transition may impact demand for certain refined products in the future, management anticipates sufficiently robust demand for the remainder of each refinery's useful life.

Headroom on goodwill balances was reduced, however the recoverable amount exceeds the carrying amount. See note 14 for further information including sensitivity analysis on the assumptions used to test goodwill for impairment.

Management will continue to review price assumptions as the energy transition progresses and this may result in impairment charges or reversals in the future.

Exploration and appraisal intangible assets

The energy transition may affect the future development or viability of exploration prospects. The lower price assumptions and work to develop bp's new strategy resulted in a review of the recoverability of exploration and appraisal intangible assets during 2020. Certain intangible assets were subsequently written-off. See significant judgement: exploration and appraisal intangible assets and note 8 for further information.

The revised long-term price assumptions for investment appraisal (see page 28) help create a framework that seeks to help ensure that currently unsanctioned future capital expenditure on property plant and equipment, and exploration and appraisal intangibles, is aligned with bp's new strategy.

Property, plant and equipment – depreciation and expected useful lives

The energy transition may curtail the expected useful lives of oil and gas industry assets thereby accelerating depreciation charges. However, the significant majority of bp's existing Upstream oil and natural gas properties are likely to be fully depreciated within the next 10 years and, as outlined in bp's new strategy, oil and natural gas production will remain an important part of bp's business activities over that period. Similarly, for Downstream refineries, demand for refined products is expected to remain strong over the remaining useful life of existing assets.

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

Therefore, management does not expect the useful lives of bp's reported property, plant and equipment to change and do not consider this to be a significant accounting judgement or estimate. Significant capital expenditure is still required for ongoing projects and therefore the useful lives of future capital expenditure may, however, be different. See significant accounting policy: property, plant and equipment for more information.

Provisions: decommissioning
The energy transition may bring forward the decommissioning of oil and gas industry assets thereby increasing the present value of associated decommissioning provisions. The majority of bp's Upstream oil and gas properties are expected to start decommissioning within the next two decades and management does not expect any reasonable change in the expected timeframe to have a material effect on the Upstream decommissioning provisions, assuming cash flows remain unchanged. Decommissioning cost estimates are based on the known regulatory and external environment. These cost estimates may change in the future, including as a result of the transition to a lower carbon economy. For Downstream refineries, decommissioning provisions are generally not recognized as the associated obligations have indeterminate settlement dates, typically driven by the cessation of manufacturing. Management will continue to review facts and circumstances to assess if decommissioning provisions need to be recognized. See significant judgements and estimates: provisions for further information.

Judgements and estimates made in assessing the impact of the COVID-19 pandemic and the economic environment
In preparing the consolidated financial statements, the following areas involving judgement and estimates were identified as most relevant with regards to the impact of the COVID-19 pandemic and current economic environment.

Going concern
Forecast liquidity has been assessed under a number of stressed scenarios, including a significant decline in oil prices over the 12-month period. Reverse stress tests performed indicated that the group will continue to operate as a going concern for at least 12 months from the date of approval of the consolidated financial statements even if the Brent price fell to zero. No material uncertainties over going concern or significant judgements or estimates in the assessment were identified. See also Note 29 Financial instruments and financial risk factors – Liquidity risk for further information.

Discount rate assumptions
The discount rates used for impairment testing and provisions were reassessed during the year in light of changing economic and geopolitical outlooks. The impact was determined not to be significant and the post-tax impairment discount rate and nominal provisions discount rate were unchanged from 2019. Pre-tax impairment discount rates and post-tax premiums for certain higher-risk countries were changed but this did not have a material impact. See significant judgements and estimates: recoverability of asset carrying values and provisions for further information.

Oil and natural gas price assumptions
The price assumptions used in value-in-use impairment testing were revised downwards during the year, in part due to lower demand for oil and natural gas. Material impairment charges and exploration write-offs were recognized in the Upstream segment as a consequence of these price assumption changes. See significant judgements and estimates: recoverability of asset carrying values and exploration and appraisal intangible assets for further information.

Demand constraints for refined products during the year did not result in any material impairment charges on Downstream refinery assets.

Pensions and other post-retirement benefits
The volatility in the financial markets during 2020 impacted the assumptions used for determining the fair value of plan assets and the present value of defined benefit obligations in the group's defined benefit pension plans. See significant estimate: pensions and other post-retirement benefits and note 24 for further information.

Impairment of financial assets measured at amortized cost
The current economic environment and future credit risk outlook were considered in updating the estimate of expected credit loss allowances on financial assets measured at amortized cost. Whilst credit risk increased relative to 31 December 2019, there was also a significant reduction in the group's trade and other receivables balance. Therefore, the total expected credit loss allowances recognized as at 31 December 2020 did not significantly increase. Management does not consider the calculation of expected credit loss allowances to be a significant accounting estimate. See note 21 and 29 for further information.

Income taxes
The carrying amounts of the group's deferred tax assets were reviewed and updated to the extent that there are changes in the probability of sufficient taxable profits being available to utilize the reported deferred tax assets. Management does not consider the measurement of deferred tax assets to be a significant accounting estimate. See significant accounting policy: income taxes and Note 9 for further information.

Basis of consolidation
The consolidated 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, including when control is obtained via potential voting rights, 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. Included within non-controlling interests are perpetual subordinated hybrid bonds issued by a subsidiary and for which the group has the unconditional right to avoid transferring cash or another financial asset to the bondholders. Profit or loss attributable to bp shareholders is adjusted to reflect the coupon related to these hybrid bonds whether or not such distribution has been deferred.

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.

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

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

Interests in joint arrangements

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

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

Interests in associates

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

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. Rosneft's largest shareholder is Rosneftegaz JSC (Rosneftegaz), which is wholly owned by the Russian government. At 31 December 2020, Rosneftegaz held 40.4% (2019 50% plus one share) of the voting shares of Rosneft . 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, Bernard Looney, was approved as a member of the board of directors of Rosneft in June 2020 as one of bp's two nominated directors. bp's other nominated director, Bob Dudley, has been a member of the Rosneft board since 2013. He is also chairman of the Rosneft board's Strategic and Sustainable Development Committee. bp also holds the voting rights at general meetings of shareholders conferred by its 19.75% stake in Rosneft. Transactions by Rosneft in its own shares during the year have increased bp's economic interest in Rosneft to 22.03% (2019 19.75%). bp's management considers, 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, apart from those that meet the definition of a derivative, 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 before interest and tax. Replacement cost profit for the group is not a recognized measure under IFRS. For further information see Note 5.

For information on changes to bp's segmental reporting see 'Change in segmentation from 1 January 2021' below.

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

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 items, other than those measured at fair value, are not retranslated subsequent to initial recognition.

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

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

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

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 or sanctioned probable 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, that is, the efforts are not successful, 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 or sanctioned probable reserves, the relevant expenditure is transferred to property, plant and equipment. If development is not approved and no further activity is expected to occur, then the costs are expensed.

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.

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

Development expenditure

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

Significant judgement: 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.

As a result of the revised price assumptions detailed in Significant judgements and estimates: recoverability of asset carrying values below and a review of bp's long-term strategic plan, management reviewed bp's exploration prospects and the carrying value of the associated intangible assets. The outcome of the review resulted in revised judgements over management's expectations to extract value from certain prospects, thereby leading to material write-offs of the associated exploration and appraisal intangible assets in 2020.

The carrying amount of capitalized costs and further information on the write-offs are 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 applicable, 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 in accordance with US Securities and Exchange Commission (SEC) regulations, including the application of prices using 12-month historical price data in assessing the commerciality of technical volumes, are typically used to calculate depreciation, depletion and amortization charges for the group's oil and gas properties. Therefore, where this approach is adopted, charges are not dependent on management forecasts of future oil and gas prices.

However, for certain oil and natural gas assets, the use of reserves determined in accordance with SEC regulations would result in a charge that is not reflective of the pattern in which the future economic benefits are expected to be consumed. In these limited instances other approaches are applied to determine the reserves base used to calculate depreciation, depletion and amortization, including the use of management's best estimate of price assumptions as disclosed in Significant judgements and estimates: recoverability of asset carrying values, to determine the commerciality of technical proved reserves.

The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining carrying value of the asset over the expected future production.

The estimation of oil and natural gas reserves and bp's process to manage reserves bookings is described in Supplementary information on oil and natural gas on page 231, which is unaudited. Details on bp's proved reserves and production compliance and governance processes are provided on page 312. The 2020 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 231.

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 10 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, plans to dispose rather than retain assets, 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. Carbon taxes and costs of emissions allowances are included in estimates of future cash flows, where applicable, based on the regulatory environment in each jurisdiction in which the group operates. 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, capital expenditure, 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 described 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 2020 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 and country risk premiums. Fair value less costs of disposal discounted cash flow calculations use the post-tax discount rate.

The discount rates applied in impairment tests are reassessed each year and in 2020, the post-tax discount rate was 6% (2019 6%). Where the CGU is located in a country that was judged to be higher risk an additional premium of 1% to 3% was reflected in the post-tax discount rate (2019 1% to 4%). The judgement of classifying a country as higher risk and the applicable premium takes into account various economic and geopolitical factors. The pre-tax discount rate typically ranged from 7% to 15% (2019 7% to 13%) depending on the risk premium and applicable tax rate in the geographic location of the CGU.

Oil and natural gas properties

For Upstream 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.

In 2020, the group identified Upstream oil and gas properties with carrying amounts totalling $45,027 million (2019 $25,092 million) where the headroom, based on the most recent impairment test performed in the year on those assets, was less than or equal to 20% of the carrying value. A change in the discount rate, reserves, resources or the oil and gas price assumptions in the next financial year may result in a recoverable amount of one or more of these assets above or below the current carrying amount and therefore there is a risk of impairment reversals or charges in that period. Management considers that reasonably possible changes in the discount rate or forecast revenue, arising from a change in oil and natural gas prices and/or production could result in a material change in their carrying amounts within the next financial year,see Sensitivity analyses, below.

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 price assumptions used for value in use impairment testing are based on those used for investment appraisal. The investment appraisal price assumptions are recommended by the senior vice president economic & energy insights after considering a range of external prices, 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.

bp sees the prospect of an enduring impact on the global economy as a result of the COVID-19 pandemic, with the potential for weaker demand for energy for a sustained period. bp’s management also expects that the aftermath of the pandemic will accelerate the pace of transition to a lower carbon economy and energy system as countries seek to ‘build back better’ so that their economies will be more resilient in the future. As a result of all the above, bp revised its price assumptions for value-in-use impairment testing, lowering them compared to those used in 2019 and extending the period covered to 2050. These price assumptions are derived from the central case investment appraisal assumptions (see page 28). A summary of the group’s revised price assumptions, in real 2020 terms, is provided below. The assumptions represent management’s best estimate of future prices, which sit within the range of external forecasts considered as appropriate for the purpose. They are considered by bp to be broadly in line with a range of transition paths consistent with the Paris climate goals. However, they do not correspond to any specific Paris-consistent scenario. An inflation rate of 2% (2019 2%) is applied to determine the price assumptions in nominal terms.

	2021	2025	2030	2040	2050
Brent oil ($/bbl)	50	50	60	60	50
Henry Hub gas ($/mmBtu)	3.00	3.00	3.00	3.00	2.75

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

Material impairment charges were recognized in 2020 following the downward revision of the price assumptions. See Note 4 for further information.

The long-term price assumptions used to determine recoverable amount based on value-in-use impairments tests in 2019 were $70 per barrel for Brent and $4 per mmBtu for Henry Hub gas, both in 2015 prices. These long-term prices were applied from 2025 and 2032 respectively inflated for the remaining life of the asset.

The price assumptions used in 2019 over the periods to 2025 and 2032 were set such that there was a linear progression from our best estimate of 2020 prices to the long-term assumptions.

The majority of bp's reserves and resources that support the carrying value of the group's existing oil and gas properties are expected to be produced over the next 10 years.

Oil prices fell 35% in 2020 from 2019 due to trade tensions, a macroeconomic downturn and a slowdown in oil demand, reflecting the impact of the COVID-19 pandemic. 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 2020 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 20% in 2020 compared to 2019. Henry Hub gas prices were already low in early 2020 due to mild weather. The drop in demand from the second quarter onward as a result of the COVID-19 pandemic as well as significant US LNG shut-ins contributed to prices remaining below $2/mmBtu during the second and third quarters, despite a record consumption in the power sector and the drop in natural gas production. Prices recovered in the fourth quarter due to the seasonal gas demand increase and the strong recovery in US LNG exports. bp's long-term price assumption for US gas reflects the fact that over the coming decades US gas production increases with an increasing proportion of production being used as feedstock to supply expanding LNG exports, while in the longer-term falling gas consumption and declining demand for global LNG exports leads to increasing competitive pressure on US gas production.

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 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 or probable.

Sensitivity analyses
A change in revenue from Upstream oil and gas properties can arise either due to changes in oil and natural gas prices, changes in oil and natural gas production, or a combination of the two.

Management tested the impact of a change in revenue cash flows in value-in-use impairment testing arising from changes in price assumptions and/or production volumes up to a combined effect on revenue of 10% in all future years.

Revenue reductions of this magnitude in isolation could indicatively lead to a reduction in the carrying amount of bp's Upstream oil and gas properties in the range of $6-7 billion, which is approximately 5-6% of the net book value of property, plant and equipment as at 31 December 2020.

Revenue increases of this magnitude in isolation could indicatively lead to an increase in the carrying amount of bp's Upstream 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 2020. This potential increase in the carrying amount would arise due to reversals of previously recognized impairments.

These sensitivity analyses do not, however, represent management's best estimate of any impairment charges or reversals that might be recognized as they do not fully incorporate consequential changes that may arise, such as changes in costs and business plans and phasing of development. For example, costs across the industry are more likely to decrease as oil and natural gas prices fall. The above sensitivity analyses therefore do not reflect a linear relationship between revenue and value that can be extrapolated. The interdependency of these inputs and risk factors plus the diverse characteristics of our Upstream 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 or production volumes.

Management also tested the impact of a one percentage point change in the discount rate used for value-in-use impairment testing of Upstream oil and gas properties. If the discount rate was one percentage point higher across all tests performed, the impairment charge recognized in 2020 would have been approximately $2.4 billion higher. If the discount rate was one percentage point lower, the impairment charge recognized would have been approximately $2.7 billion lower.

Goodwill

Irrespective of whether there is any indication of impairment, bp is required to test annually for impairment of goodwill acquired in business combinations. The group carries goodwill of approximately $12.5 billion on its balance sheet (2019 $11.9 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.

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

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. Repayments of principal are presented as financing cash flows and payments of interest are presented as operating cash flows.

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 and presented as operating cash flows. 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.

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. This may be the case if for example bp, as operator of the joint operation, is the sole signatory to the lease. 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.

Financial assets

Financial assets are recognized initially at fair value, normally being the transaction price. In the case of financial assets not measured 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 and either substantially all of the risks and rewards of the asset have been transferred, or substantially all the risks and rewards of the asset have neither been retained nor transferred but control of the asset has been transferred. 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.

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.

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

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

Derivatives designated as hedging instruments in an effective hedge
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.

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 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.

Equity instruments
Instruments are classified as either financial liabilities or as equity in accordance with the substance of the contractual arrangements. Instruments that cannot be settled in the group's own equity instruments and that include no contractual obligation to deliver cash or another financial asset or to exchange financial assets or financial liabilities with another entity that are potentially unfavourable are classified as equity. Equity instruments issued by the group are recognized at the proceeds received, net of direct issue costs.

Financial liabilities
Financial liabilities are recognized when the group becomes party to the contractual provisions of the instrument. The group derecognizes financial liabilities when the obligation specified in the contract is discharged, cancelled or expired. 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.

Significant judgement: supplier financing arrangements
The group's trade payables include some supplier arrangements that utilize letter of credit facilities. Judgement is required to 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 and whether the arrangements significantly change the nature of the liability. 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. See Note 29 - Liquidity risk for further information.

Financial guarantees
The group issues financial guarantee contracts to make specified payments to reimburse holders for losses incurred because certain associates, joint ventures or third-party entities fail to make payments when due in accordance with the original or modified terms of a debt instrument such as a loan. The liability for a financial guarantee contract is initially measured at fair value and subsequently measured at the higher of the contract's estimated expected credit loss and the amount initially recognized less, where appropriate, cumulative amortization.

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.

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

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 a '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:

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.

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

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 or to determine appropriate presentation and classification of transactions in certain cases. In particular 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 the inability or lack of history of net settlement 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% (2019 2.5%).

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

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

Decommissioning

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

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.

Emissions

Liabilities for emissions are recognized when the cumulative volumes of gases emitted by the group at the end of the reporting period exceed the allowances granted free of charge held for own use or a set baseline for emissions. The provision is measured at the best estimate of the expenditure required to settle the present obligation at the balance sheet date. It is based on the excess of actual emissions over the free allowances held or set baseline in tonnes (or other appropriate quantity) and is valued at the actual cost of any allowances that have been purchased and held for own use on a first-in-first-out (FIFO) basis, and, if insufficient allowances are held, for the remaining requirement on the basis of the spot market price of allowances at the balance sheet date. The cost of allowances purchased to cover a shortfall is recognized separately on the balance sheet as an intangible asset unless the emission allowances acquired or generated by the group are risk-managed by the integrated supply and trading function, then they are recognized on the balance sheet as inventory.

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

Restructuring provisions

The reinvent bp programme, expected to reduce headcount by around 10,000 positions, has resulted in recognition of provisions where a detailed formal plan exists, and a valid expectation of risk of redundancy has been made to those affected but where the specific outcomes remain uncertain . Where formal redundancy offers have been made, the obligations for those amounts are reported as payables and, if not, as provisions if unpaid at the year-end.

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 2020 (2019 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 are generally not recognized, as the potential obligations cannot be measured, given their indeterminate settlement dates.Obligations may arise if refineries cease manufacturing operations and any such obligations would be recognized in the period when sufficient information becomes available to determine potential settlement dates.

The group performs periodic reviews of its downstream refineries for any changes in facts and circumstances including those relating to the energy transition, 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. The interest rate used in discounting the cash flows is reviewed quarterly. The nominal interest rate used to determine the balance sheet obligations at the end of 2020 was 2.5% (2019 2.5%), 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 (2019 18 years) and 6 years (2019 6 years) respectively. Costs at future prices are determined by applying an inflation rate of 1.5% (2019 1.5%) to decommissioning costs and 2% (2019 2%) for all other provisions. A lower rate is applied to decommissioning as certain costs are expected to remain fixed at current or past prices.

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 percentage point decrease in the nominal discount rate applied could increase the group's provision balances by approximately $1.3 billion (2019 $1.4 billion). The pre-tax impact on the group income statement would be a charge of approximately $0.5 billion.

The discounting impact on the group's Upstream decommissioning provisions of a two-year change in the timing of expected future decommissioning expenditures would not be material. Management currently does not consider a change of greater than two years to be reasonably possible in the next financial year.

If all expected future decommissioning expenditures were 10% higher, the group's Upstream decommissioning provisions would increase by approximately $1.4 billion and a pre-tax charge of approximately $0.5 billion would be recognized.

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.

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.

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

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.

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.

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.

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.Such judgements are inherently impacted by estimates affecting future taxable profits such as oil and natural gas prices and decommissioning expenditure, see significant judgements and estimates: recoverability of asset carrying values and provisions

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 2020 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.

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 forward contracts entered into by the group that result in physical delivery of products such as crude oil, natural gas and refined products are required to be accounted for as derivative financial instruments. Revenue recognized relating to such contracts when physical delivery occurs is measured at the contractual transaction price plus the carrying amount of the related derivative at the date of settlement and presented as other operating revenues. Changes in the fair value of derivative assets and liabilities prior to physical delivery are also classified as other operating revenues. See also Other significant accounting policy changes - *IFRIC agenda decision on IFRS 9 'Financial instruments'* below.

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

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.

Updates to significant accounting policies

Impact of new International Financial Reporting Standards

bp adopted 'Interest Rate Benchmark Reform – Phase I – Amendments to IFRS 9 'Financial instruments' and IFRS 7 'Financial instruments: Disclosures'' with effect from 1 January 2020. There are no other new or amended standards or interpretations adopted during the year that have a significant impact on the consolidated financial statements.

'Interest Rate Benchmark Reform – Phase I'

Financial authorities in the US, UK, EU and other territories are currently undertaking reviews of key interest rate benchmarks such as the London Inter-bank Offered Rate (LIBOR) with a view to replacing them with alternative benchmarks. Uncertainty around the method and timing of transition from Inter-bank Offered Rates (IBORs) to alternative risk-free rates (RfRs) may impact the assessment of whether hedge accounting can be applied to certain hedging relationships.

This first phase of amendments to IFRS 9 provide temporary relief from applying specific hedge accounting requirements to hedging relationships directly affected by interest rate benchmark reforms.

In accordance with the transition provisions, the amendments have been adopted retrospectively to hedging relationships that existed at the start of the current reporting period and have been applied to new hedging relationships designated after that date.

The reliefs have meant that the uncertainty over the interest rate benchmark reforms has not resulted in discontinuation of hedge accounting for any of bp's fair value hedges.

See Note 29 Financial instruments and financial risk factors - interest rate risk and Note 30 Derivative financial instruments - Fair value hedges for further information.

Impact of new International Financial Reporting Standards - 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. 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 2023. The standard has not yet been endorsed by the UK and the EU. bp's assessment of the impact of IFRS 17 is at an initial stage but it is not expected to have a significant effect on future financial reporting.

'Interest Rate Benchmark Reform – Phase II'

Amendments to IFRS 9, IFRS 7, IFRS 4 and IFRS 16 'Leases' were issued by the IASB in August 2020 to provide practical expedients and reliefs in relation to modifications of financial instruments and leases that arise from transition from IBORs to RFRs. Phase II also provides further reliefs to hedge accounting requirements. These amendments were effective for bp from 1 January 2021. The amendments have been endorsed by the UK and by the EU.

bp's working group on interest rate benchmark reform is monitoring and managing the transition to alternative benchmark rates and is currently assessing the impact on contracts and arrangements that are linked to existing interest rate benchmarks for example, borrowings, leases and derivative contracts. bp is also participating on external committees and task forces dedicated to interest rate benchmark reform.

Other changes to significant accounting policies

Physically settled derivative contracts

In March 2019, 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. 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 routinely enters into transactions for the sale and purchase of commodities that are physically settled and meet the definition of a derivative financial instrument. As described in the group's accounting policy for revenue in bp Annual Report and Form 20-F 2019, revenue recognized at the time such contracts were physically settled was measured at the contractual transaction price and was presented together with revenue from contracts with customers in those financial statements.

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

bp changed its accounting policy for these contracts, in accordance with the conclusions included in the agenda decision, with effect from 1 April 2020, as follows:

- Revenues and purchases from such contracts are measured at the contractual transaction price plus the carrying amount of the related derivative at the date of settlement. Realized derivative gains and losses on physically settled derivative contracts are included in other revenues.
- There is no significant effect on current period or comparative information for 'Sales and other operating revenues' and 'Purchases' as presented in the group income statement, therefore no comparative information has been re-stated.
- There is no significant effect on net assets or on comparative information for 'Profit before taxation' or 'Profit after taxation' as presented in the group income statement.

In addition, bp chose to change its presentation of revenues from physically settled derivative sales contracts from 1 January 2020. Revenues from physically settled derivative sales contracts are no longer presented together with revenue from contracts with customers. In these financial statements they are now presented as other revenues. Comparative information in Note 6 for revenue from contracts with customers and other revenues have been re-presented to align with the current period as set out below.

						$ million
	2019 (previously reported)	2019 (re-presented – see note 6)	Presentational adjustments	2018 (previously reported)	2018 (re-presented – see note 6)	Presentational adjustments
Crude oil	62,130	9,141	52,989	65,276	10,331	54,945
Oil products	180,528	102,408	78,120	195,466	108,515	86,951
Natural gas, LNG and NGLs	20,167	18,909	1,258	21,745	20,494	1,251
Non-oil products and other revenues from contracts with customers	13,254	12,169	1,085	13,768	12,489	1,279
Revenue from contracts with customers	276,079	142,627	133,452	296,255	151,829	144,426
Other operating revenues	2,318	135,770	(133,452)	2,501	146,927	(144,426)
Total sales and other operating revenues	278,397	278,397	—	298,756	298,756	—

Voluntary changes to significant accounting policies - not yet adopted

Net presentation of revenues and purchases relating to physically settled derivative contracts from 1 January 2021

As described above, bp routinely enters into transactions for the sale and purchase of commodities that are physically settled and meet the definition of a derivative financial instrument. These contracts are within the scope of IFRS 9 and as such, prior to settlement, changes in the fair value of these derivative contracts are presented as gains and losses within other operating revenues. The group currently presents revenues and purchases for such contracts on a gross basis in the group income statement upon physical settlement. These transactions have historically represented a substantial portion of the revenues and purchases reported in the group's consolidated financial statements.

The change in strategic direction of the group supported by organisational changes to implement the strategy from 1 January 2021, results in the group determining that the revenue and corresponding purchases relating to such transactions should be presented net as gains or losses within other operating revenues. Additionally the group's trading activity has continued to evolve over time from one of capturing third party physical trades to provide flow assurance to one with increasing levels of optimisation, taking advantage of price volatility and fluctuations in demand and supply, which will continue under the new strategy, further supporting the change in presentation. The new presentation provides reliable and more relevant information for users of the accounts as the group's revenue recognition will be more closely aligned with its assessment of 'Scope 3' emissions from its products, its 'Net Zero' ambition and how management monitors and manages performance of such contracts. Comparative information for Sales and other operating revenues and purchases for 2019 and 2020 will be restated and will be presented under the new policy alongside group's 2021 financial information.

Change in segmentation

During the first quarter of 2021, the group's reportable segments changed consistent with a change in the way that resources are allocated and performance is assessed by the chief operating decision maker, who for bp is the group chief executive, from that date. From the first quarter of 2021, the group's reportable are gas & low carbon energy, oil production & operations, customers & products, and Rosneft. At 31 December 2020, the group's reportable segments were Upstream, Downstream and Rosneft.

Gas & low carbon energy comprises regions with upstream businesses that predominantly produce natural gas, gas trading activities and the group's renewables businesses, including biofuels, solar and wind. Gas producing regions were previously in the Upstream segment. The group's renewables businesses were previously part of 'Other businesses and corporate'.

Oil production & operations comprises regions with upstream activities that predominantly produce crude oil. These activities were previously in the Upstream segment.

Customers & products comprises the group's convenience and mobility business, which manages the sale of fuels to wholesale and retail customers, convenience products, aviation fuels, and Castrol lubricants; and refining, supply and trading. The petrochemicals business will also be reported in restated comparative information as part of the customers and products segment up to its sale in December 2020. The customers & products segment is, therefore, substantially unchanged from the former Downstream segment with the exception of the Petrochemicals disposal.

The Rosneft segment is unchanged and continues to include equity-accounted earnings from the group's investment in Rosneft.

The segment measure of profit or loss continues to be replacement cost profit or loss before interest and tax, which reflects the replacement cost of supplies by excluding from profit or loss before interest and tax inventory holding gains and losses. See Note 5 for further information.

In the group's financial reporting for 2021, comparative information for 2019 and 2020 will be restated to reflect the changes in reportable segments. Reporting under the new segment structure will begin with the first quarter 2021 interim financial statements.

Segmental information presented in these financial statements is based on the segment structure as at 31 December 2020.

2. Non-current assets held for sale

The carrying amount of assets classified as held for sale at 31 December 2020 is $1,326 million (2019 $7,465 million), with associated liabilities of $46 million (2019 $1,393 million).

Upstream segment

The balance consists primarily of a 20% participating interest from bp's 60% participating interest in Block 61 in Oman. As announced on 1 February 2021, bp has agreed to sell this interest to PTT Exploration and Production Public Company Limited of Thailand for a total consideration of up to $2.6 billion, subject to final adjustments. Under the terms of the agreement, bp will receive $2,450 million on completion, with up to an additional $140 million receivable contingent on pre-agreed future conditions. Subject to approvals, the transaction is expected to complete during 2021. Assets of $1,298 million and associated liabilities of $10 million have been classified as held for sale in the group balance sheet at 31 December 2020.

Transactions that have been classified as held for sale during 2020, but were completed by 31 December 2020, are described below.

Downstream segment

On 29 June 2020 bp announced that it had agreed to sell its global petrochemicals business to INEOS for a total consideration of $5 billion, subject to customary closing adjustments. The assets and liabilities of the business were classified as held for sale from that date until the disposal completed on 31 December 2020. Under the terms of the agreement, INEOS paid bp a deposit of $400 million and a further $3.6 billion on completion less $0.1 billion of third-party indebtedness remaining in petrochemicals on completion. The remaining $1 billion was received in February 2021. The business had interests in manufacturing plants in Asia, Europe and the US, including interests held in equity-accounted entities. See note 4 for further information.

Upstream segment

On 27 August 2019, bp announced that it had agreed to sell its Alaska operations and interests to Hilcorp Energy for up to $5.6 billion, subject to customary closing adjustments. The sale included bp's upstream and midstream business in the state, including BP Exploration (Alaska) Inc., which owned 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). These assets and associated liabilities were classified as held for sale in the 31 December 2019 group balance sheet. The disposal of BP Exploration (Alaska) Inc. completed on 30 June 2020. The disposal of TAPS completed on 18 December 2020.

bp received $800 million prior to or on completion of the disposals and has recognized a loan note with a principal amount of $2,100 million receivable from Hilcorp. The group has also recognized other assets totalling $1,722 million as at 31 December 2020, principally in relation to the 'earn-out' provisions of the agreement. See note 4 for information on impairment charges relating to the Alaska business.

bp retained decommissioning liability relating to the TAPS, which will be partially offset by a 30% cost reimbursement from Hilcorp when incurred.

In November 2019, bp agreed to sell its interests in the San Juan basin in Colorado and New Mexico to IKAV. These assets and associated liabilities were classified as held for sale in the 31 December 2019 group balance sheet. The transaction completed on 28 February 2020.

The total assets and liabilities held for sale at 31 December 2020 and 2019, which are all in the Upstream segment, are set out in the table below.

		$ million
	2020	2019
Property, plant and equipment	**1,099**	6,359
Goodwill	**199**	—
Intangible assets	**—**	610
Investments in associates	**—**	43
Inventories	**—**	318
Trade and other receivables	**28**	135
Assets classified as held for sale	**1,326**	7,465
Trade and other payables	**(36)**	(33)
Lease liabilities	**—**	(280)
Provisions	**(10)**	(1,012)
Defined benefit pension plan and other post-retirement benefit plan deficits	**—**	(68)
Liabilities directly associated with assets classified as held for sale	**(46)**	(1,393)

3. Business combinations and other significant transactions

Business combinations

2020

The group undertook a number of business combinations during 2020. The fair value of the net assets (including goodwill) and non-controlling interests recognized were $617 million and $574 million, respectively. These principally related to an acquisition in our US Fuels business.

2019

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. A number of other individually insignificant business combinations were also undertaken by bp in 2019.

4. Disposals and impairment

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

			$ million
	2020	2019	2018
Gains on sale of businesses and fixed assets			
Upstream	**360**	143	437
Downstream	**2,320**	50	15
Other businesses and corporate	**194**	—	4
	2,874	193	456

			$ million
	2020	2019	2018
Losses on sale of businesses and fixed assets, and closures			
Upstream	**383**	415	707
Downstream	**296**	57	59
Other businesses and corporate	**2**	887	11
	681	1,359	777
Impairment losses			
Upstream	**12,917**	6,752	400
Downstream	**840**	65	12
Other businesses and corporate	**32**	30	254
	13,789	6,847	666
Impairment reversals			
Upstream	**(86)**	(131)	(580)
Downstream	**—**	—	(2)
Other businesses and corporate	**(3)**	—	(1)
	(89)	(131)	(583)
Impairment and losses on sale of businesses and fixed assets, and closures	**14,381**	8,075	860

Disposals

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

			$ million
	2020	2019	2018
Proceeds from disposals of fixed assets	**491**	500	940
Proceeds from disposals of businesses, net of cash disposed	**4,989**	1,701	1,911
	5,480	2,201	2,851
By business			
Upstream	**1,175**	2,048	2,145
Downstream	**3,959**	152	120
Other businesses and corporate	**346**	1	586
	5,480	2,201	2,851

Proceeds from disposals of business in 2020 includes $3,888 million in respect of the disposal of the Petrochemical business and $347 million in respect of the disposal of the Alaska business. At 31 December 2020, deferred consideration relating to disposals amounted to $1,291 million receivable within one year (2019 $159 million and 2018 $35 million) and $2,402 million receivable after one year (2019 $125 million and 2018 $304 million). The deferred consideration principally relates to the disposals of our Petrochemical and Alaskan businesses. In addition, contingent consideration receivable relating to disposals amounted to $1,999 million at 31 December 2020 (2019 $598 million and 2018 $893 million).The contingent consideration at 31 December 2020 relates to the disposal of our Alaskan business and prior period disposals in the North Sea. These amounts of contingent consideration are reported within Other investments on the group balance sheet - see Note 18 for further information.

Gains and losses on sale of businesses and fixed assets, and closures

Upstream

In 2020, gains principally resulted from adjustments to disposals in prior periods. Gains include $130 million from the disposal of our Alaska operations and interests and $166 million fair value movements in relation to deferred and contingent consideration in relation to the Alaska disposal and prior disposals in the North Sea. Losses included $134 million fair value movements in relation to deferred and contingent consideration arising from prior period disposals in the North Sea, $120 million in relation to the likely disposal of an exploration asset, and $78 million from the disposal of certain properties in the US.

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, and adjustments to disposals in prior periods.

4. Disposals and impairment – continued

Downstream

In 2020, gains principally resulted from the $2.3 billion gain recognised on the disposal of our Petrochemicals business which completed in December 2020. Losses included $229 million in relation to cessation of manufacturing operations at the Kwinana Refinery following the decision to cease fuel production.

Other businesses and corporate

In 2020 the gain on disposal of businesses and fixed assets was principally in respect of the sale and leaseback of our St James's Square London headquarters - see Note 28 for further information.

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 transactions categorized as a business disposal in 2020 were the sales of our Petrochemical and Alaskan businesses. See Note 2 for further information.

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.

						$ million
				2020	2019	2018
	Alaska	Petrochemicals	Other	Total		
Non-current assets	5,143	2,592	1,357	9,092	1,653	3,274
Current assets	693	846	—	1,539	507	173
Non-current liabilities	(923)	(178)	(538)	(1,639)	(257)	(250)
Current liabilities	(344)	(425)	(13)	(782)	(108)	(97)
Total carrying amount of net assets disposed	4,569	2,835	806	8,210	1,795	3,100
Recycling of foreign exchange on disposal	—	(331)	3	(328)	880	—
Costs on disposal	(6)	(25)	44	13	190	3
	4,563	2,479	853	7,895	2,865	3,103
Gains (losses) on sale of businesses	260	2,414	(104)	2,570	(1,190)	(221)
Total consideration	4,823	4,893	749	10,465	1,675	2,882
Non-cash consideration	(219)	—	—	(219)	(938)	(282)
Consideration received (receivable)[a]	(4,257)	(1,005)	5	(5,257)	964	(689)
Proceeds from the sale of businesses, net of cash disposed[b]	347	3,888	754	4,989	1,701	1,911

[a] In 2019 $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 $101 million (2019 $30 million and 2018 $15 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 2020 impairment loss of $12,917 million primarily relates to losses incurred in respect of producing and development assets in the UK North Sea ($2,796 million), the US ($2,744 million), Trinidad ($2,416 million), Mauritania and Senegal ($1,909 million), India ($1,313 million) and Canada ($865 million). Impairment losses were primarily driven by a reduction in bp's future oil and gas price assumptions and, to a lesser extent, certain technical reserves revisions. The recoverable amount of the impaired CGUs in total is $33,415 million.

The principal CGUs on which significant impairment losses were incurred in 2020 were $1,909 million for Tortue in Mauritania and Senegal; $1,313 million for KGD6 in India; $1,181 million for Schiehallion in the UK North Sea; $1,044 million for Mahogany in Trinidad, $960 million for Cassia in Trinidad; $1,011 million for Hawkville in BPX Energy; $747 million for ETAP in the UK North Sea and $742 million for Sunrise in Canada. The recoverable amount for each of these CGUs was their value in use, which in total was $13,200 million. In addition, impairment losses of $939 million were incurred relating to the disposal of bp's business in Alaska. The recoverable amount of the Alaska business was its fair value less costs of disposal; see note 2 for further information.

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.

Downstream

Impairment losses totalling $840 million, $65 million, and $12 million were recognized in 2020, 2019 and 2018 respectively. The amount for 2020 principally relates to portfolio changes in the fuels business, including the conversion of Kwinana refinery to an import terminal. None of the impairment charges were individually material.

4. Disposals and impairment – continued

Other businesses and corporate

Impairment losses totalling $32 million, $30 million, and $254 million were recognized in 2020, 2019 and 2018 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 2020, 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 before interest and tax inventory holding gains and losses[a]. Replacement cost profit or loss before interest and tax 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 reorganization of the group's organizational structure. The group's segmental reporting structure as described above remained in place throughout 2020. Changes to this structure, as described in Note 1 - Voluntary changes to significant accounting policies - not yet adopted, came 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

2020

By business	**Upstream**	**Downstream**	**Rosneft**	**Other businesses and corporate**	**Consolidation adjustment and eliminations**	**Total group**
Segment revenues						
Sales and other operating revenues	**34,197**	**162,974**	**—**	**1,716**	**(18,521)**	**180,366**
Less: sales and other operating revenues between segments	**(17,130)**	**(158)**	**—**	**(1,233)**	**18,521**	**—**
Third party sales and other operating revenues	**17,067**	**162,816**	**—**	**483**	**—**	**180,366**
Earnings from joint ventures and associates – after interest and tax	**(268)**	**214**	**(229)**	**(120)**	**—**	**(403)**
Segment results						
Replacement cost profit (loss) before interest and taxation	**(21,547)**	**3,418**	**(149)**	**(683)**	**89**	**(18,872)**
Inventory holding gains (losses)[a]	**17**	**(2,796)**	**(89)**	**—**	**—**	**(2,868)**
Profit (loss) before interest and taxation	**(21,530)**	**622**	**(238)**	**(683)**	**89**	**(21,740)**
Finance costs						**(3,115)**
Net finance expense relating to pensions and other post-retirement benefits						**(33)**
Profit before taxation						**(24,888)**
Other income statement items						
Depreciation, depletion and amortization						
US	**3,772**	**1,359**	**—**	**63**	**—**	**5,194**
Non-US	**7,447**	**1,631**	**—**	**617**	**—**	**9,695**
Charges for provisions, net of write-back of unused provisions, including change in discount rate	**56**	**1,903**	**—**	**543**	**—**	**2,502**
Segment assets						
Investments in joint ventures and associates	**10,749**	**3,671**	**11,808**	**1,109**	**—**	**27,337**
Additions to non-current assets[b]	**8,743**	**5,359**	**—**	**655**	**—**	**14,757**

[a] See explanation of inventory holding gains and losses on page 180.

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

$ 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 180.

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

5. Segmental analysis – continued

						$ million
						2018
By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
Segment revenues						
Sales and other operating revenues	56,399	270,689	—	1,678	(30,010)	298,756
Less: sales and other operating revenues between segments	(28,565)	(574)	—	(871)	30,010	—
Third party sales and other operating revenues	27,834	270,115	—	807	—	298,756
Earnings from joint ventures and associates – after interest and tax	951	589	2,283	(70)	—	3,753
Segment results						
Replacement cost profit (loss) before interest and taxation	14,328	6,940	2,221	(3,521)	211	20,179
Inventory holding gains (losses)[a]	(6)	(862)	67	—	—	(801)
Profit (loss) before interest and taxation	14,322	6,078	2,288	(3,521)	211	19,378
Finance costs						(2,528)
Net finance expense relating to pensions and other post-retirement benefits						(127)
Profit 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 180.
[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.

			$ million
			2020
By geographical area	**US**	**Non-US**	**Total**
Revenues			
Third party sales and other operating revenues[a]	**55,611**	**124,755**	**180,366**
Other income statement items			
Production and similar taxes	**57**	**638**	**695**
Non-current assets			
Non-current assets[b c]	**52,493**	**108,786**	**161,279**

[a] Non-US region includes UK $42,729 million
[b] Non-US region includes UK $19,583 million
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

			$ 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.

5. Segmental analysis – continued

By geographical area	US	Non-US	$ million 2018 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.

6. Sales and other operating revenues

	2020	2019	$ million 2018
Crude oil	**5,048**	9,141	10,331
Oil products	**63,564**	102,408	108,515
Natural gas, LNG and NGLs	**12,726**	18,909	20,494
Non-oil products and other revenues from contracts with customers	**9,840**	12,169	12,489
Revenue from contracts with customers	**91,178**	142,627	151,829
Other operating revenues[a]	**89,188**	135,770	146,927
Total sales and other operating revenues	**180,366**	278,397	298,756

[a] Principally relates to physically settled derivative sales contracts.

An analysis of third-party sales and other operating revenues by segment and region is provided in Note 5.

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.

Amounts shown for revenue from contracts with customers and other operating revenues for 2018 and 2019 have been represented to align with the current period. See Note 1 - Other changes to significant accounting policies - *Physically settled derivative contracts* for further information.

7. Income statement analysis

	2020	2019	$ million 2018
Interest and other income			
Interest income from			
Financial assets measured at amortized cost	**215**	371	421
Financial assets measured at fair value through profit or loss	**25**	49	39
Other income	**423**	349	313
	663	769	773
Currency exchange losses charged to the income statement[a]	**38**	37	368
Expenditure on research and development	**332**	364	429
Costs relating to the Gulf of Mexico oil spill (pre-interest and tax)[b]	**255**	319	714
Finance costs			
Interest expense on lease liabilities[c]	**337**	379	51
Interest expense on other liabilities measured at amortized cost[d]	**2,166**	2,410	2,147
Capitalized at 2.75% (2019 3.50% and 2018 3.56%)[e]	**(345)**	(374)	(419)
Unwinding of discount on provisions[f]	**437**	505	210
Unwinding of discount on other payables measured at amortized cost	**520**	569	539
	3,115	3,489	2,528

[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 2018 comparative period relates to leases previously classified as finance leases under IAS 17.

[d] 2020 includes a loss of $158 million associated with the buyback of finance debt.

[e] Tax relief on capitalized interest is approximately $83 million (2019 $51 million and 2018 $55 million).

[f] 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
	2020	2019	2018
Exploration and evaluation costs			
Exploration expenditure written off[a]	**9,920**	631	1,085
Other exploration costs	**360**	333	360
Exploration expense for the year	**10,280**	964	1,445
Impairment losses	**156**	2	137
Intangible assets – exploration and appraisal expenditure[b c]	**4,113**	14,091	15,989
Liabilities	**71**	73	60
Net assets	**4,042**	14,018	15,929
Cash used in operating activities	**360**	333	360
Cash used in investing activities	**674**	1,215	1,119

[a] 2020 includes $2,643 million in the Gulf of Mexico primarily relating to the Paleogene assets, $2,539 million in Canada primarily relating to Terre de Grace, $2,141 million in Brazil, $952 million in Egypt and $832 million in Angola. 2018 included $447 million in the deepwater Gulf of Mexico principally relating to licence expiries. For further information see Upstream – Exploration on page .

[b] 2019 includes approximately $2.5 billion relating to Canadian oil sands.

[c] Amount capitalized at 31 December 2020 relates to assets in various regions. The largest of these is $0.7 billion capitalised in the Middle East region.

9. Taxation

Tax on profit

			$ million
	2020	2019	2018
Current tax			
Charge for the year	**2,095**	5,316	6,217
Adjustment in respect of prior years[a]	**50**	(68)	(221)
	2,145	5,248	5,996
Deferred tax[b]			
Origination and reversal of temporary differences in the current year	**(7,826)**	(1,190)	907
Adjustment in respect of prior years	**1,522**	(94)	242
	(6,304)	(1,284)	1,149
Tax charge (credit) on profit or loss	**(4,159)**	3,964	7,145

[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. 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; 2020 includes charges for the reassessment of deferred tax asset recognition in light of revisions to price assumptions.

In 2020, the total tax charge recognized within other comprehensive income was $39 million (2019 $227 million charge and 2018 $714 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 $154 million (2019 $37 million charge and 2018 $17 million charge). 2020 principally relates to a non-controlling interest transaction entered into by Rosneft.

Reconciliation of the effective tax rate

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

9. Taxation – continued

			$ million
	2020	2019	2018
Profit (loss) before taxation	**(24,888)**	8,154	16,723
Tax charge (credit) on profit or loss	**(4,159)**	3,964	7,145
Effective tax rate	**17%**	49%	43%

			%
Tax rate computed at the weighted average statutory rate[a]	**31**	52	43
Increase (decrease) resulting from			
Tax reported in equity-accounted entities	**—**	(7)	(5)
Adjustments in respect of prior years	**(6)**	(2)	—
Deferred tax not recognized	**(3)**	(2)	1
Tax incentives for investment	**1**	(3)	(2)
Foreign exchange	**(1)**	1	3
Items not deductible for tax purposes	**(3)**	4	1
Other	**(2)**	6	2
Effective tax rate	**17**	49	43

[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.

Deferred tax

		$ million
Analysis of movements during the year in the net deferred tax (asset) liability	**2020**	2019
At 31 December	**5,190**	6,106
Adjustment on adoption of IFRS 16	**—**	(75)
At 1 January	**5,190**	6,031
Exchange adjustments	**55**	72
Credit for the year in the income statement	**(6,304)**	(1,284)
Charge for the year in other comprehensive income	**48**	233
Charge for the year in equity	**154**	37
Acquisitions and disposals	**(56)**	101
At 31 December	**(913)**	5,190

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

					$ million
		Income statement[a]			Balance sheet
	2020	2019	2018	**2020**	2019
Deferred tax liability					
Depreciation	**(7,295)**	(1,436)	(1,297)	**15,361**	22,627
Pension plan surpluses	**69**	(31)	65	**2,691**	2,290
Derivative financial instruments	**33**	29	(36)	**63**	29
Other taxable temporary differences	**(32)**	159	(57)	**1,562**	1,496
	(7,225)	(1,279)	(1,325)	**19,677**	26,442
Deferred tax asset					
Depreciation	**(849)**	—	—	**(849)**	—
Lease liabilities	**286**	264	8	**(1,122)**	(1,380)
Pension plan and other post-retirement benefit plan deficits	**2**	62	(6)	**(1,548)**	(1,367)
Decommissioning, environmental and other provisions	**438**	(472)	1,505	**(7,155)**	(7,579)
Derivative financial instruments	**—**	63	(31)	**(25)**	(24)
Tax credits	**310**	(336)	123	**(3,652)**	(3,964)
Loss carry forward	**543**	12	559	**(5,319)**	(5,834)
Other deductible temporary differences	**191**	402	316	**(920)**	(1,104)
	921	(5)	2,474	**(20,590)**	(21,252)
Net deferred tax charge (credit) and net deferred tax (asset) liability[b]	**(6,304)**	(1,284)	1,149	**(913)**	5,190
Of which – deferred tax liabilities				**6,831**	9,750
– deferred tax assets				**7,744**	4,560

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

[b] Included within the net deferred tax (asset) liability is a deferred tax asset balance of $5,471 million (2019 $5,526 million) related to the Gulf of Mexico oil spill.

9. Taxation – continued

Of the $7,744 million of deferred tax assets recognised on the group balance sheet at 31 December 2020 (2019 $4,560 million), $7,659 million (2019 $2,421 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 2020, $3,906 million relates to the US, $707 million relates to India, $637 million relates to Australia and $588 million relates to Trinidad & Tobago (2019 $2,421 million relates to the US).

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

		$ billion
At 31 December	2020	2019
Unused US state tax losses[a]	2.4	2.3
Unused tax losses – other jurisdictions[b]	6.0	3.5
Unused tax credits	26.9	25.4
of which – arising in the UK[c]	23.0	21.5
– arising in the US[d]	3.9	3.9
Deductible temporary differences[e]	46.1	40.4
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	0.8	1.5

[a] For 2020 these losses expire in the period 2021-2040 with applicable tax rates ranging from 3% to 10%.

[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 2020 the US unused tax credits expire in the period 2021-2030.

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

			$ million
Impact of previously unrecognized deferred tax or write-down of deferred tax assets on tax charge	2020	2019	2018
Current tax benefit relating to the utilization of previously unrecognized deferred tax assets	46	272	83
Deferred tax benefit arising from the reversal of a previous write-down of deferred tax assets	11	96	—
Deferred tax benefit relating to the recognition of previously unrecognized deferred tax assets	—	364	112
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	1,622	73	169

10. Dividends

The quarterly dividend which is expected to be paid on 26 March 2021 in respect of the fourth quarter 2020 is 5.25 cents per ordinary share ($0.315 per American Depositary Share (ADS)). The corresponding amount in sterling was announced on 15 March 2021.

	Pence per share			Cents per share			$ million		
	2020	2019	2018	2020	2019	2018	2020	2019	2018
Dividends announced and paid in cash									
Preference shares							1	1	1
Ordinary shares									
March	8.1558	7.7382	7.1691	10.50	10.25	10.00	2,102	1,435	1,828
June	8.3421	8.0655	7.4435	10.50	10.25	10.00	2,119	1,779	1,727
September	4.0433	8.3475	7.9296	5.25	10.25	10.25	1,059	1,656	1,409
December	3.9169	7.8250	8.0251	5.25	10.25	10.25	1,059	2,075	1,734
	24.4581	31.9762	30.5673	31.50	41.00	40.50	6,340	6,946	6,699
Dividend announced, paid in March 2021				5.25			1,067		

The amount of unclaimed dividends recognised as a liability at 31 December 2020 is $50 million (2019 $22 million).

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 any dividends announced since the third quarter 2019, including the fourth quarter 2020 dividend expected to be paid on 26 March 2021.

	2020	2019	2018
Number of shares issued (thousand)	—	208,927	195,305
Value of shares issued ($ million)	—	1,387	1,381

The financial statements for the year ended 31 December 2020 do not reflect the dividend announced on 2 February 2021 and paid in March 2021; this will be treated as an appropriation of profit in the year ending 31 December 2021.

11. Earnings per share

Per ordinary share	2020	2019	2018
			Cents per share
Basic earnings per share	**(100.42)**	19.84	46.98
Diluted earnings per share	**(100.42)**	19.73	46.67

Per American Depositary Share (ADS)	2020	2019	2018
			Dollars per share
Basic earnings per share	**(6.03)**	1.19	2.82
Diluted earnings per share	**(6.03)**	1.18	2.80

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.

	2020	2019	2018
			$ million
Profit attributable to bp shareholders	**(20,305)**	4,026	9,383
Less: dividend requirements on preference shares	**1**	1	1
Profit for the year attributable to bp ordinary shareholders	**(20,306)**	4,025	9,382

	2020	2019	2018
			Shares thousand
Basic weighted average number of ordinary shares	**20,221,514**	20,284,859	19,970,215
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**—**	114,811	132,278
Weighted average number of ordinary shares outstanding used to calculate diluted earnings per share	**20,221,514**	20,399,670	20,102,493

	2020	2019	2018
			Shares thousand
Basic weighted average number of ordinary shares – ADS equivalent	**3,370,252**	3,380,809	3,328,369
Potential dilutive effect of ordinary shares (ADS equivalent) issuable under employee share-based payment plans	**—**	19,136	22,046
Weighted average number of ordinary shares (ADS equivalent) outstanding used to calculate diluted earnings per share	**3,370,252**	3,399,945	3,350,415

The number of ordinary shares outstanding at 31 December 2020, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 20,264,027,711. Between 31 December 2020 and 25 February 2021, the latest practicable date before the completion of these financial statements, there was a net increase of 66,249,231 in the number of ordinary shares outstanding primarily as a result of share issues in relation to employee share-based payment plans.

Employee share-based payment plans

The group operates share and share option plans for directors and certain employees to obtain ordinary shares and ADSs in the company. Information on these plans for directors is shown in the Directors remuneration report on pages 103-126.

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	2020		2019	
	Number of options[a b] thousand	**Weighted average exercise price $**	Number of options[a b] thousand	Weighted average exercise price $
Outstanding	**28,171**	**3.79**	17,112	4.91
Exercisable	**1,874**	**5.02**	1,067	3.97
Dilutive effect	**2,497**	**n/a**	3,990	n/a

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

[b] At 31 December 2020 the quoted market price of one bp ordinary share was £2.55 (2019 £4.72).

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.

11. Earnings per share – continued

Share plans	2020	2019
	Number of shares[a]	Number of shares[a]
Vesting	thousand	thousand
Within one year	**87,517**	91,105
1 to 2 years	**85,720**	89,939
2 to 3 years	**147,097**	80,844
3 to 4 years	**749**	725
Over 4 years	**349**	576
	321,432	263,189
Dilutive effect	**104,068**	92,343

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

There has been a net decrease of 29,718,486 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2020 and 25 February 2021.

12. Property, plant and equipment (PP&E)

	Land and land improvements	Buildings	Oil and gas properties[a]	Plant, machinery and equipment	Fittings, fixtures and office equipment	Transportation	Oil depots, storage tanks and service stations	Total
								$ million
Cost - owned PP&E								
At 1 January 2020	**3,609**	**1,422**	**214,352**	**46,724**	**2,532**	**3,474**	**8,694**	**280,807**
Exchange adjustments	**219**	**6**	**—**	**801**	**33**	**8**	**603**	**1,670**
Additions	**101**	**63**	**6,922**	**1,539**	**586**	**49**	**864**	**10,124**
Acquisitions	**89**	**—**	**—**	**35**	**5**	**9**	**376**	**514**
Transfers from intangible assets	**—**	**—**	**605**	**—**	**—**	**—**	**—**	**605**
Reclassified as assets held for sale	**—**	**—**	**(1,425)**	**—**	**—**	**—**	**—**	**(1,425)**
Deletions	**(146)**	**(281)**	**(6,131)**	**(6,185)**	**(738)**	**(491)**	**(261)**	**(14,233)**
At 31 December 2020	**3,872**	**1,210**	**214,323**	**42,914**	**2,418**	**3,049**	**10,276**	**278,062**
Depreciation - owned PP&E								
At 1 January 2020	**581**	**697**	**124,766**	**21,527**	**2,006**	**2,744**	**4,865**	**157,186**
Exchange adjustments	**35**	**6**	**—**	**424**	**26**	**9**	**379**	**879**
Charge for the year	**113**	**46**	**10,068**	**1,312**	**170**	**77**	**740**	**12,526**
Impairment losses	**8**	**9**	**11,705**	**744**	**2**	**4**	**3**	**12,475**
Impairment reversals	**—**	**(1)**	**(83)**	**—**	**—**	**(5)**	**—**	**(89)**
Reclassified as assets held for sale	**—**	**—**	**(326)**	**—**	**—**	**—**	**—**	**(326)**
Deletions	**(45)**	**(126)**	**(5,579)**	**(3,976)**	**(359)**	**(448)**	**(201)**	**(10,734)**
At 31 December 2020	**692**	**631**	**140,551**	**20,031**	**1,845**	**2,381**	**5,786**	**171,917**
Owned PP&E - net book amount at 31 December 2020	**3,180**	**579**	**73,772**	**22,883**	**573**	**668**	**4,490**	**106,145**
Right-of-use assets - net book amount at 31 December 2020[b]	**—**	**1,254**	**77**	**792**	**21**	**2,855**	**3,692**	**8,691**
Total PP&E - net book amount at 31 December 2020	**3,180**	**1,833**	**73,849**	**23,675**	**594**	**3,523**	**8,182**	**114,836**
Cost - owned 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[b]	—	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
Assets under construction included above								
At 31 December 2020								**17,259**
At 31 December 2019								23,897
Depreciation charge for the year on right-of-use assets								
2020		**192**	**43**	**637**	**10**	**829**	**579**	**2,290**
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] $284 million (2019 $653 million) of drilling rig right-of-use assets and $2,521 million (2019 $2,929 million) of shipping vessel right-of-use assets are included in Plant, machinery and equipment and Transportation respectively.

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 2020 amounted to $8,009 million (2019 $11,382 million, 2018 $8,319 million). bp has contracted capital commitments amounting to $1,087 million (2019 $77 million, 2018 $25 million) in relation to joint ventures and $183 million (2019 $787 million, 2018 $1,227 million) in relation to associates. bp's share of contracted capital commitments of joint ventures amounted to $900 million (2019 $1,024 million, 2018 $619 million).

14. Goodwill and impairment review of goodwill

		$ million
	2020	2019
Cost		
At 1 January	12,865	12,815
Exchange adjustments	184	79
Acquisitions and other additions[a]	632	26
Reclassified as assets held for sale	(199)	—
Deletions	(389)	(55)
At 31 December	13,093	12,865
Impairment losses		
At 1 January	997	611
Exchange adjustments	1	—
Impairment losses for the year	1	386
Deletions	(386)	—
At 31 December	613	997
Net book amount at 31 December	12,480	11,868
Net book amount at 1 January	11,868	12,204

[a] 2020 principally relates to an acquisition in the US Fuels business.

Impairment review of goodwill

		$ million
Goodwill at 31 December	2020	2019
Upstream	7,765	7,958
Downstream	4,660	3,904
Other businesses and corporate	55	6
	12,480	11,868

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

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

Upstream

		$ million
	2020	2019
Goodwill	7,765	7,958
Excess of recoverable amount over carrying amount	31,749	93,250

The table above shows the carrying amount of goodwill for the segment at the period end 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 most recent test. The reduction in headroom since the prior period principally relates to the impact of changes to price assumptions.

No impairment of the Upstream goodwill balance was recognized during 2020 (2019 $386 million).

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, as they do not represent 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 each field is computed using appropriate individual economic models and key assumptions agreed by bp management.

Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis, including operating and capital expenditure, are derived from the business segment plan. 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. Oil and gas price assumptions and discount rate assumptions used were as disclosed in Note 1. The average production for the purposes of goodwill impairment testing over the next 15 years is 877 mmboe per year (2019 829 mmboe per year). The weighted average pre-tax discount rate used in the test is 11% (2019 12%).

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. 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 or production 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 or savings. A detailed calculation at any given price or production profile may, therefore, produce a different result.

Adverse changes in input assumptions applied in respect to assets carried at or close to their value in use, primarily being those assets previously impaired, would have a limited effect on goodwill headroom, instead resulting in a direct impairment of the particular cash-generating unit's net book value. Conversely, a reduction in the value in use of those assets carried at a value below their respective values in use would result in an adverse impact on the goodwill headroom. It is estimated that a 21% reduction in revenue throughout each year of the remaining life of those assets, either as a result of adverse price or production conditions or a combination of each, 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 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.

Downstream

										$ million
					2020					2019
	Lubricants	US Fuels	European Fuels	Other	Total	Lubricants	US Fuels	European Fuels	Other	Total
Goodwill	2,865	606	913	276	4,660	2,779	—	858	267	3,904

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 2020 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
			2020			2019
	Exploration and appraisal expenditure[a]	Other intangibles	Total	Exploration and appraisal expenditure[a]	Other intangibles	Total
Cost						
At 1 January	15,306	4,900	20,206	17,053	4,504	21,557
Exchange adjustments	—	138	138	—	2	2
Acquisitions	—	318	318	—	35	35
Additions	703	645	1,348	1,268	457	1,725
Transfers to property, plant and equipment	(605)	—	(605)	(1,885)	—	(1,885)
Reclassified as assets held for sale	—	—	—	(671)	—	(671)
Deletions	(987)	(379)	(1,366)	(459)	(98)	(557)
At 31 December	14,417	5,622	20,039	15,306	4,900	20,206
Amortization						
At 1 January	1,215	3,452	4,667	1,064	3,209	4,273
Exchange adjustments	—	93	93	—	4	4
Exploration expenditure written off	9,920	—	9,920	631	—	631
Charge for the year	—	372	372	—	331	331
Impairment losses	156	9	165	2	2	4
Reclassified as assets held for sale	—	—	—	(61)	—	(61)
Deletions	(987)	(284)	(1,271)	(421)	(94)	(515)
At 31 December	10,304	3,642	13,946	1,215	3,452	4,667
Net book amount at 31 December	4,113	1,980	6,093	14,091	1,448	15,539
Net book amount at 1 January	14,091	1,448	15,539	15,989	1,295	17,284

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

16. Investments in joint ventures

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

			$ million
	2020	2019[a]	2018
Sales and other operating revenues	**10,545**	14,139	13,258
Profit before interest and taxation	**(151)**	976	1,396
Finance costs	**201**	109	85
Profit before taxation	**(352)**	867	1,311
Taxation	**(51)**	289	414
Non-controlling interest	**1**	2	—
Profit for the year	**(302)**	576	897
Other comprehensive income	**(5)**	(6)	6
Total comprehensive income	**(307)**	570	903
Non-current assets	**12,646**	13,457	
Current assets	**3,424**	3,738	
Total assets	**16,070**	17,195	
Current liabilities	**2,644**	2,514	
Non-current liabilities	**5,023**	4,676	
Total liabilities	**7,667**	7,190	
Net assets	**8,403**	10,005	
Less: non-controlling interests	**39**	49	
	8,364	9,956	
Group investment in joint ventures			
Group share of net assets (as above)	**8,364**	9,956	
Loans made by group companies to joint ventures	**(2)**	35	
	8,362	9,991	

[a] 2019 has been restated to include non-controlling interest

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

Sales to joint ventures	2020		2019		2018	$ million
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	**2,974**	**180**	4,884	431	4,603	251

Purchases from joint ventures	2020		2019		2018	$ million
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	**959**	**84**	1,812	225	1,336	300

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.

bp's share of impairment charges taken by joint ventures in 2020 was $433 million (2019 $25 million reversal) of which $336 million (2019 $25 million reversal) was in the Upstream segment.

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	
	2020	2019	2018	2020	2019
Rosneft	**(229)**	2,295	2,283	**11,808**	12,927
Other associates	**128**	386	573	**7,167**	7,407
	(101)	2,681	2,856	**18,975**	20,334

The associate that is material to the group at both 31 December 2020 and 2019 is Rosneft.

17. Investments in associates – continued

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. Rosneft's largest shareholder is Rosneftegaz JSC (Rosneftegaz), which is wholly owned by the Russian government. At 31 December 2020, Rosneftegaz held 40.4% (2019 50.0% plus one share) of the voting shares of Rosneft.

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 decrease in the group's equity-accounted investment balance for Rosneft at 31 December 2020 compared with 31 December 2019 principally relates to adverse foreign exchange effects, which have been recognized in other comprehensive income, and dividends, partially offset by bp's share of Rosneft's changes in equity.

During 2020 Rosneft completed a transaction to transfer all of its interest and cease participation in its Venezuelan businesses to a company owned by the government of the Russian Federation. In consideration, Rosneft received shares equal to a 9.6% share of its own equity. The shares are held by a 100% subsidiary of Rosneft and accounted for as treasury shares. Rosneft also entered into share buyback transactions during the year. These are also accounted for as treasury shares. bp retains 19.75% of the voting rights at meetings of Rosneft shareholders and will continue to be entitled to dividends based on its current shareholding. bp's economic interest, however, increased as a result of its indirect interest in the shares held by the subsidiary of Rosneft. bp's share of profit or loss of Rosneft reflects its economic interest. At 31 December 2020, bp's economic interest was 22.03%.

On 28 December 2020 Rosneft completed the acquisition of 100% stakes in JSC Taimyrneftegaz and LLC Taimyrburservis, and the sale of a 10% interest in LLC Vostok Oil. A preliminary assessment of the fair values of the assets and liabilities acquired and the consideration transferred in respect of the acquisitions has been undertaken and the further impact, if any, on bp's accounting for its equity-accounted investment in Rosneft will be updated once this has been finalised.

The value of bp's 19.75% shareholding in Rosneft based on the quoted market share price of $5.64 per share (2019 $7.21 per share) was $11,804 million at 31 December 2020 (2019 $15,090 million). The value of bp's 22.03% economic interest based on the quoted market share price was $13,167 million at 31 December 2020.

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.

			$ million
			Gross amount
	2020	2019	2018
Sales and other operating revenues	**82,786**	134,046	131,322
Profit before interest and taxation	**1,270**	17,473	18,886
Finance costs	**1,742**	1,281	2,785
Profit (loss) before taxation	**(472)**	16,192	16,101
Taxation	**208**	3,058	2,957
Non-controlling interests	**482**	1,514	1,585
Profit (loss) for the year	**(1,162)**	11,620	11,559
Other comprehensive income	**1,653**	572	2,086
Total comprehensive income	**491**	12,192	13,645
Non-current assets	**175,978**	161,327	
Current assets	**42,459**	38,657	
Total assets	**218,437**	199,984	
Current liabilities	**49,781**	44,459	
Non-current liabilities	**96,727**	79,327	
Total liabilities	**146,508**	123,786	
Net assets	**71,929**	76,198	
Less: non-controlling interests	**10,897**	10,744	
	61,032	65,454	

The group received dividends, net of withholding tax, of $480 million from Rosneft in 2020 (2019 $785 million and 2018 $620 million).

17. Investments in associates – continued

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

									$ million bp share
			2020			2019			2018
	Rosneft[a]	Other	Total	Rosneft[a]	Other	Total	Rosneft[a]	Other	Total
Sales and other operating revenues	**17,535**	**5,946**	**23,481**	26,474	7,934	34,408	25,936	9,134	35,070
Profit before interest and taxation	**295**	**276**	**571**	3,451	788	4,239	3,730	1,150	4,880
Finance costs	**372**	**80**	**452**	253	87	340	550	78	628
Profit (loss) before taxation	**(77)**	**196**	**119**	3,198	701	3,899	3,180	1,072	4,252
Taxation	**51**	**67**	**118**	604	315	919	584	499	1,083
Non-controlling interests	**101**	**1**	**102**	299	—	299	313	—	313
Profit (loss) for the year	**(229)**	**128**	**(101)**	2,295	386	2,681	2,283	573	2,856
Other comprehensive income	**336**	**(19)**	**317**	113	(25)	88	412	(1)	411
Total comprehensive income	**107**	**109**	**216**	2,408	361	2,769	2,695	572	3,267
Non-current assets	**33,754**	**11,449**	**45,203**	31,862	11,504	43,366			
Current assets	**8,238**	**1,749**	**9,987**	7,635	1,924	9,559			
Total assets	**41,992**	**13,198**	**55,190**	39,497	13,428	52,925			
Current liabilities	**9,535**	**1,346**	**10,881**	8,781	1,908	10,689			
Non-current liabilities	**18,558**	**4,709**	**23,267**	15,667	4,577	20,244			
Total liabilities	**28,093**	**6,055**	**34,148**	24,448	6,485	30,933			
Net assets	**13,899**	**7,143**	**21,042**	15,049	6,943	21,992			
Less: non-controlling interests	**2,091**	**—**	**2,091**	2,122	—	2,122			
	11,808	**7,143**	**18,951**	12,927	6,943	19,870			
Group investment in associates									
Group share of net assets (as above)	**11,808**	**7,143**	**18,951**	12,927	6,943	19,870			
Loans made by group companies to associates	**—**	**24**	**24**	—	464	464			
	11,808	**7,167**	**18,975**	12,927	7,407	20,334			

[a] In 2014-2019, Rosneft adopted hedge accounting in relation to a portion of highly probable future export revenue denominated in US dollars. Foreign exchange gains and losses arising on the retranslation of borrowings denominated in currencies other than the Russian rouble and designated as hedging instruments were recognized initially in other comprehensive income, and were reclassified to the income statement as the hedged revenue was recognized.

During the year, bp and Reliance Industries completed the formation of a new fuels and mobility venture, Reliance BP Mobility Limited, that will operate across India under the Jio-bp brand. bp invested $1 billion to acquire a 49% stake in the company.

Transactions between the group and its associates are summarized below.

						$ million
Sales to associates		2020		2019		2018
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	**855**	**169**	1,544	243	2,064	393

						$ million
Purchases from associates		2020		2019		2018
Product	**Purchases**	**Amount payable at 31 December**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
Crude oil and oil products, natural gas, transportation tariff	**4,926**	**1,280**	9,503	1,641	14,112	2,069

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 $10,777 million (2019 $11,198 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.

bp's share of impairment charges taken by associates in 2020 was $414 million (2019 $152 million).

18. Other investments

				$ million
		2020		2019
	Current	Non-current	Current	Non-current
Equity investments[a]	**—**	**913**	—	571
Contingent consideration	**317**	**1,682**	122	476
Other	**16**	**151**	47	229
	333	**2,746**	169	1,276

[a] Approximately half of the group's equity investments are unlisted.

Contingent consideration relates to amounts arising on disposals 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. The contingent consideration principally relates to the disposal of our Alaskan business.

19. Inventories

		$ million
	2020	2019
Crude oil	**4,498**	5,610
Natural gas	**265**	222
Emissions allowances[a]	**1,297**	1,193
Refined petroleum and petrochemical products	**8,791**	11,714
	14,851	18,739
Trading inventories	**292**	182
	15,143	18,921
Supplies	**1,730**	1,959
	16,873	20,880
Cost of inventories expensed in the income statement	**132,104**	209,672

[a] Comparative period has been re-presented to align with the current period.

The inventory valuation at 31 December 2020 is stated net of a provision of $584 million (2019 $650 million) to write down inventories to their net realizable value, of which $216 million (2019 $290 million) relates to hydrocarbon inventories. The net credit to the income statement in the year in respect of inventory net realizable value provisions was $17 million (2019 $348 million credit), of which $71 million credit (2019 $309 million credit) related to hydrocarbon inventories.

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

20. Trade and other receivables

				$ million
		2020		2019
	Current	Non-current	Current	Non-current
Financial assets				
Trade receivables	**12,926**	**19**	19,424	22
Amounts receivable from joint ventures and associates	**339**	**10**	672	2
Receivables related to disposals[a]	**1,291**	**2,402**	159	125
Other receivables	**2,628**	**637**	3,166	701
	17,184	**3,068**	23,421	850
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset	**32**	**—**	201	—
Sales taxes and production taxes	**557**	**504**	640	538
Other receivables	**175**	**779**	180	759
	764	**1,283**	1,021	1,297
	17,948	**4,351**	24,442	2,147

[a] For further information see Note 4 - Disposals and Impairment.

In both 2020 and 2019 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, other than certain receivables related to disposals, are predominantly non-interest bearing. See Note 29 for further information.

21. Valuation and qualifying accounts

						$ million
	2020		2019		2018	
	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	**509**	**249**	416	235	335	314
Adjustment on adoption of IFRS 9	**—**	**—**	—	—	115	(85)
At 1 January – IFRS 9	**509**	**249**	416	235	450	229
Charged to costs and expenses	**214**	**103**	206	28	30	10
Charged to other accounts[a]	**2**	**—**	(2)	—	(12)	(1)
Deductions	**(170)**	**(166)**	(111)	(14)	(52)	(3)
At 31 December	**555**	**186**	509	249	416	235

[a] Principally exchange adjustments.

Valuation and qualifying accounts relating to trade and other receivables comprise expected credit loss allowances. 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 $456 million (2019 $414 million, 2018 $327 million) relating to receivables that were credit-impaired at the end of the year and $99 million (2019 $95 million, 2018 $89 million) relating to receivables that were not credit-impaired at the end of the year. Whilst credit risk has increased since 31 December 2019, there has also been a significant reduction in the group's trade and other receivables balance. Therefore, the total expected credit loss allowances recognized as at 31 December 2020 have not significantly increased during the year.

Valuation and qualifying accounts relating to fixed asset investments comprise impairment provisions for investments 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 (2019 $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

				$ million
	2020		2019	
	Current	Non-current	Current	Non-current
Financial liabilities				
Trade payables	**23,157**	**—**	30,538	—
Amounts payable to joint ventures and associates	**1,364**	**—**	1,866	—
Payables for capital expenditure and acquisitions	**2,297**	**1,033**	3,868	1,196
Payables related to the Gulf of Mexico oil spill	**1,399**	**9,988**	1,617	10,863
Other payables	**5,041**	**681**	5,810	133
	33,258	**11,702**	43,699	12,192
Non-financial liabilities				
Sales taxes, customs duties, production taxes and social security	**2,103**	**73**	2,381	33
Other payables	**653**	**337**	749	401
	2,756	**410**	3,130	434
	36,014	**12,112**	46,829	12,626

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 payables related to the Gulf of Mexico oil spill for these elements of the agreements are $4,837 million payable over 12 years, $2,584 million payable over 13 years and $3,549 million payable over 12 years respectively at 31 December 2020. Reported within net cash provided by operating activities in the group cash flow statement is a net cash outflow of $1,786 million (2019 outflow of $2,694 million, 2018 outflow of $3,531 million) related to the Gulf of Mexico oil spill, which includes payments made in relation to these agreements. For 2018 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* - Legal Proceedings.

Payables related to the Gulf of Mexico oil spill at 31 December 2020 also include amounts payable for settled economic loss and property damage claims which are payable over a period of up to seven years.

23. Provisions

						$ million
	Decommissioning	Environmental	Litigation and claims	Emissions	Other	Total
At 1 January 2020	**15,110**	**1,620**	**1,281**	**919**	**2,021**	**20,951**
Exchange adjustments	96	9	1	25	84	215
Increase (decrease) in existing provisions	(686)	297	260	1,429	974	2,274
Write-back of unused provisions	(11)	(88)	(12)	(17)	(341)	(469)
Unwinding of discount	369	39	18	—	11	437
Utilization	(7)	(246)	(508)	(687)	(378)	(1,826)
Reclassified to other payables	(245)	—	(129)	—	(86)	(460)
Reclassified as liabilities directly associated with assets held for sale	(10)	—	—	—	—	(10)
Deletions	(140)	(2)	(1)	—	(8)	(151)
At 31 December 2020	**14,476**	**1,629**	**910**	**1,669**	**2,277**	**20,961**
Of which – current	428	273	260	1,621	1,179	3,761
– non-current	14,048	1,356	650	48	1,098	17,200

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. The emissions provision relates to the group's obligation to transfer emissions allowances under relevant regulations. The provision will principally be settled through allowances already held as inventory in the group balance sheet. Included within the other category at 31 December 2020 are reinvent bp restructuring provisions for employee termination payments of $428 million.

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

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.

Litigation and claims

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 Deepwater Horizon Court Supervised Settlement Programme (DHCSSP), which commenced operation on 4 June 2012. On 22 January 2021, the United States District Court for the Eastern District of Louisiana issued an order determining the completion of all claims processing operations of the DHCSSP. The Court also concluded that future issues concerning EPD Settlement Agreement claims would be time barred under the DHCSSP and the claim administrator would proceed to complete post-closure administrative wind down activities. Amounts payable for settled economic and property damage claims are reported within payables - see Note 22 for further information.

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 226.

The litigation and claims provision reflects the latest estimate for the remaining costs associated with the Gulf of Mexico oil spill. The amounts payable may differ from the amount provided and the timing of payments is uncertain.

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, one independent director and one 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 and is currently under consultation for closure to future accrual. As at 31 December 2020, it remained 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 2020 the committee was composed of seven bp employees appointed by the president of bp Corporation North America Inc. (the appointing officer). The Investment Committee is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as the investment policies of the plan. US employees are also eligible to participate in a defined contribution (401k) plan in which employee contributions are matched with company contributions. In the US, group companies also provide post-retirement healthcare to most 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.

24. Pensions and other post-retirement benefits – continued

In the Eurozone, there are defined benefit pension plans in Germany, France, the Netherlands and other countries. In Germany and France, the majority of the pensions are unfunded, in line with market practice. In Germany, the group's largest Eurozone plan, employees receive a pension and also have a choice to supplement their core pension through salary sacrifice. For employees who joined since 2002, the core pension benefit is a career average plan with retirement benefits based on such factors as an employee's pensionable salary and length of service. The returns on the notional contributions made by both the company and employees are 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 2020 the aggregate level of contributions was $325 million (2019 $349 million and 2018 $610 million). The aggregate level of contributions in 2021 is expected to be approximately $400 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 a schedule of contributions is agreed covering the next five years. Contractually committed funding amounted to $1,014 million at 31 December 2020, 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 307.

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.

Minimum pension funding in the US is determined by legislation and is supplemented by discretionary contributions. No contributions were made into the primary US pension plan in 2020 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 2020.

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 2020. 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, and a valuation as at 31 December 2020 is currently underway. 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.

									%
			UK			US			Eurozone
Financial assumptions used to determine benefit obligation	**2020**	2019	2018	**2020**	2019	2018	**2020**	2019	2018
Discount rate for plan liabilities	**1.4**	2.1	2.9	**2.2**	3.1	4.1	**1.0**	1.3	2.0
Rate of increase in salaries	**3.6**	3.4	3.8	**4.1**	3.9	3.9	**2.9**	3.1	3.1
Rate of increase for pensions in payment	**2.8**	2.7	3.0	**—**	—	—	**1.3**	1.5	1.5
Rate of increase in deferred pensions	**2.8**	2.7	3.0	**—**	—	—	**0.5**	0.5	0.5
Inflation for plan liabilities	**2.9**	2.7	3.1	**1.7**	1.5	1.5	**1.5**	1.7	1.7

									%
			UK			US			Eurozone
Financial assumptions used to determine benefit expense	**2020**	2019	2018	**2020**	2019	2018	**2020**	2019	2018
Discount rate for plan service cost	**2.1**	3.0	2.6	**3.2**	4.2	3.6	**1.8**	2.5	2.4
Discount rate for plan other finance expense	**2.1**	2.9	2.5	**3.1**	4.1	3.5	**1.3**	2.0	1.9
Inflation for plan service cost	**2.6**	3.1	3.1	**1.5**	1.5	1.7	**1.7**	1.7	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.

24. Pensions and other post-retirement benefits – continued

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

									Years
Mortality assumptions			UK			US			Eurozone
	2020	2019	2018	**2020**	2019	2018	**2020**	2019	2018
Life expectancy at age 60 for a male currently aged 60	**26.9**	27.3	27.4	**24.7**	24.9	25.1	**25.7**	25.7	25.6
Life expectancy at age 60 for a male currently aged 40	**28.4**	28.9	28.9	**26.4**	26.7	26.9	**28.2**	28.3	28.1
Life expectancy at age 60 for a female currently aged 60	**28.8**	28.7	28.8	**27.7**	28.0	28.5	**29.0**	29.1	29.0
Life expectancy at age 60 for a female currently aged 40	**30.4**	30.5	30.6	**29.2**	29.7	30.1	**31.2**	31.2	31.2

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. During 2020, the UK plan switched 11% of plan assets from equities to bonds (2019 2%). There is a similar agreement in place for the primary US plan, although no switches have taken place in 2019 or 2020.

The current asset allocation policy for the major plans at 31 December 2020 was as follows:

	UK	**US**
Asset category	**%**	**%**
Total equity (including private equity)	**17**	**40**
Bonds/cash (including LDI)	**76**	**60**
Property/real estate	**7**	**—**

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2020 were $4,217 million (2019 $4,804 million) of government-issued nominal bonds and $24,576 million (2019 $19,462 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 is included in other assets in the table below.

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 201.

24. Pensions and other post-retirement benefits – continued

					$ million
	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2020					
Listed equities – developed markets	**5,008**	**1,112**	**542**	**318**	**6,980**
– emerging markets	**418**	**115**	**68**	**70**	**671**
Private equity[c]	**2,899**	**1,604**	**—**	**4**	**4,507**
Government issued nominal bonds[d]	**4,303**	**1,839**	**1,111**	**616**	**7,869**
Government issued index-linked bonds[d]	**24,576**	**—**	**107**	**—**	**24,683**
Corporate bonds[d]	**8,906**	**2,398**	**587**	**279**	**12,170**
Property[e]	**2,553**	**—**	**110**	**28**	**2,691**
Cash	**1,392**	**267**	**51**	**163**	**1,873**
Other	**795**	**131**	**104**	**30**	**1,060**
Debt (repurchase agreements) used to fund liability driven investments	**(9,387)**	**—**	**—**	**—**	**(9,387)**
	41,463	**7,466**	**2,680**	**1,508**	**53,117**
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

[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
					2020
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	250	292	103	38	683
Past service cost[b]	(48)	(66)	12	(20)	(122)
Settlement[b]	—	(23)	10	(1)	(14)
Operating charge relating to defined benefit plans	202	203	125	17	547
Payments to defined contribution plans	49	183	2	38	272
Total operating charge	251	386	127	55	819
Interest income on plan assets[a]	(725)	(210)	(33)	(40)	(1,008)
Interest on plan liabilities	596	289	97	59	1,041
Other finance (income) expense	(129)	79	64	19	33
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	4,108	1,041	104	38	5,291
Change in financial assumptions underlying the present value of the plan liabilities	(4,207)	(1,178)	(143)	(42)	(5,570)
Change in demographic assumptions underlying the present value of the plan liabilities	585	29	56	(4)	666
Experience gains and losses arising on the plan liabilities	54	(101)	(178)	8	(217)
Remeasurements recognized in other comprehensive income	540	(209)	(161)	—	170
Movements in benefit obligation during the year					
Benefit obligation at 1 January	29,780	10,119	7,353	1,826	49,078
Exchange adjustments	1,303	—	720	64	2,087
Operating charge relating to defined benefit plans	202	203	125	17	547
Interest cost	596	289	97	59	1,041
Contributions by plan participants[c]	21	—	2	11	34
Benefit payments (funded plans)[d]	(1,291)	(1,441)	(81)	(86)	(2,899)
Benefit payments (unfunded plans)[d]	(8)	(197)	(265)	(34)	(504)
Reclassified as assets held for sale	—	(1)	(55)	—	(56)
Disposals	—	(35)	—	—	(35)
Remeasurements	3,568	1,250	265	38	5,121
Benefit obligation at 31 December[a e]	34,171	10,187	8,161	1,895	54,414
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	36,129	7,655	2,343	1,412	47,539
Exchange adjustments	1,582	—	235	64	1,881
Interest income on plan assets[a f]	725	210	33	40	1,008
Contributions by plan participants[c]	21	—	2	11	34
Contributions by employers (funded plans)	189	8	99	29	325
Benefit payments (funded plans)[d]	(1,291)	(1,441)	(81)	(86)	(2,899)
Reclassified as assets held for sale	—	(7)	(55)	—	(62)
Remeasurements[f]	4,108	1,041	104	38	5,291
Fair value of plan assets at 31 December[g]	41,463	7,466	2,680	1,508	53,117
Surplus (deficit) at 31 December	7,292	(2,721)	(5,481)	(387)	(1,297)
Represented by					
Asset recognized	7,567	269	59	62	7,957
Liability recognized	(275)	(2,990)	(5,540)	(449)	(9,254)
	7,292	(2,721)	(5,481)	(387)	(1,297)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	7,564	269	(109)	(58)	7,666
Unfunded	(272)	(2,990)	(5,372)	(329)	(8,963)
	7,292	(2,721)	(5,481)	(387)	(1,297)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(33,899)	(7,197)	(2,789)	(1,566)	(45,451)
Unfunded	(272)	(2,990)	(5,372)	(329)	(8,963)
	(34,171)	(10,187)	(8,161)	(1,895)	(54,414)

[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 credits represent curtailment gains arising from restructuring programmes in the UK, US and other countries, whilst past service costs and settlements in the Eurozone represent charges for special termination benefits reflecting the increased liability arising as a result of early retirements. Settlement costs in the US resulted from a pension risk transfer to an external carrier for a group of small benefit retirees.

[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 $2,935 million benefits and $428 million settlements, plus $40 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for the US is made up of $7,728 million for pension liabilities and $2,459 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $5,060 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 199.

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 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 199.

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	—	—	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

[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 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 2020 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 2021 comprise the total of current service cost and net finance income or expense.

						$ million
						One percentage point
	UK		**US**		**Eurozone**	
	Increase	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
Discount rate[a]						
Effect on expense in 2021	**(274)**	**198**	**(51)**	**36**	**(2)**	**(11)**
Effect on obligation at 31 December 2020	**(5,658)**	**7,690**	**(1,272)**	**1,556**	**(1,149)**	**1,452**
Inflation rate[b]						
Effect on expense in 2021	**145**	**(116)**	**10**	**(8)**	**35**	**(28)**
Effect on obligation at 31 December 2020	**5,337**	**(4,482)**	**66**	**(55)**	**1,025**	**(870)**
Salary growth						
Effect on expense in 2021	**31**	**(27)**	**12**	**(10)**	**7**	**(7)**
Effect on obligation at 31 December 2020	**670**	**(585)**	**82**	**(69)**	**91**	**(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
			One year increase
	UK	**US**	**Eurozone**
Longevity			
Effect on expense in 2021	**28**	**5**	**8**
Effect on obligation at 31 December 2020	**1,406**	**150**	**333**

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 2030 and the weighted average duration of the defined benefit obligations at 31 December 2020 are as follows:

					$ million
Estimated future benefit payments	**UK**	**US**	**Eurozone**	**Other**	**Total**
2021	**1,072**	**1,568**	**357**	**112**	**3,109**
2022	**1,086**	**612**	**346**	**109**	**2,153**
2023	**1,120**	**593**	**339**	**107**	**2,159**
2024	**1,141**	**575**	**332**	**108**	**2,156**
2025	**1,135**	**583**	**328**	**107**	**2,153**
2026-2030	**5,939**	**2,696**	**1,521**	**528**	**10,684**
					Years
Weighted average duration	**19.2**	**13.8**	**16.1**	**12.7**	

25. Cash and cash equivalents

		$ million
	2020	2019
Cash	**6,235**	6,462
Triparty repos and term bank deposits	**17,368**	10,296
Cash equivalents (excluding triparty repos and term bank deposits)	**7,508**	5,714
	31,111	22,472

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; deposits of three months or less with banks and similar institutions; money market funds and commercial paper. The carrying amounts of cash, triparty repos 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 2020 includes $1,917 million (2019 $1,676 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 $3,890 million (2019 $4,678 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
			2020			2019
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**9,359**	**63,305**	**72,664**	10,487	57,237	67,724

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 $8,122 million (2019 $8,166 million) and issued commercial paper of $1,004 million (2019 $2,279 million). Finance debt does not include accrued interest, which is reported within other payables. As part of actively managing its debt portfolio, during the year the group bought back $4.0 billion equivalent (2019 $nil) of euro and sterling bonds and terminated derivatives associated with the debt bought back. In addition on 18 December 2020 the group exercised its option to redeem finance debt with an outstanding aggregate principal amount of $2.0 billion on 22 January 2021. On 19 March 2021 the group bought back a further $1.9 billion equivalent of euro and sterling bonds and terminated associated derivatives. These transactions have no significant impact on net debt or gearing.

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

			Fixed rate debt		**Floating rate debt**	**Total**
	Weighted average interest rate %	**Weighted average time for which rate is fixed Years**	**Amount $ million**	**Weighted average interest rate %**	**Amount $ million**	**Amount $ million**
						2020
US dollar	**3**	**8**	**39,452**	**2**	**32,891**	**72,343**
Other currencies	**6**	**9**	**178**	**5**	**143**	**321**
			39,630		**33,034**	**72,664**
						2019
US dollar	4	5	25,634	3	41,871	67,505
Other currencies	6	10	183	7	36	219
			25,817		41,907	67,724

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 2020, 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
		2020		2019
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**1,237**	**1,237**	2,321	2,321
Long-term borrowings	**74,855**	**71,427**	67,055	65,403
Total finance debt	**76,092**	**72,664**	69,376	67,724

27. Capital disclosures and net debt

The group defines capital as total equity plus net debt. 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, 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 total equity. 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.

At 31 December 2020, gearing was 31.3% (2019 31.1%).

		$ million
At 31 December	2020	2019
Finance debt	72,664	67,724
Less: fair value asset (liability) of hedges related to finance debt[a]	2,612	(190)
	70,052	67,914
Less: cash and cash equivalents	31,111	22,472
Net debt	38,941	45,442
Total equity[b]	85,568	100,708
Gearing	31.3 %	31.1 %

[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 $236 million (2019 liability of $601 million) are not included in the calculation of net debt shown above as hedge accounting was not applied for these instruments.

[b] Total equity in 2020 includes perpetual hybrid bonds issued on 17 June 2020. See Note 32 for further information.

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

					$ million
	Finance debt	Currency swaps[a]	Lease liabilities	Net partner payable for leases entered into on behalf of joint operations	Total liabilities arising from financing activities
At 1 January 2020	67,724	918	9,722	290	78,654
Exchange adjustments	349	—	181	4	534
Net financing cash flow	1,589	(226)	(2,442)	(40)	(1,119)
Fair value (gains) losses	2,612	(3,734)	—	—	(1,122)
New and remeasured leases/joint operation payables	—	—	1,579	20	1,599
Other movements	390	77	222	(7)	682
At 31 December 2020	72,664	(2,965)	9,262	267	79,228
At 1 January 2019	65,132	1,486	667	—	67,285
Adjustment on adoption of IFRS16	—	—	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	(570)	—	—	354
New and remeasured leases/joint operations payables	—	—	2,614	82	2,696
Other movements	59	—	(416)	(3)	(360)
At 31 December 2019	67,724	918	9,722	290	78,654

[a] Previously reported in this column were hedge accounted derivatives related to finance debt. This has been updated in 2020 as described below and comparatives provided on a consistent basis. Currency swaps include cross currency interest rate swaps.

The balances above do not include accrued interest, which is reported within other receivables and other payables on the balance sheet and for which the associated cash flows are presented as operating cash flows in the group cash flow statement. The currency swaps are reported on the balance sheet within the headings 'Derivative financial instruments' and are subsets of both derivatives held for trading and derivatives designated in fair value hedge relationships as detailed in Note 30. When hedge accounting is applied to these derivatives they are included in the calculation of net debt shown above.

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 8 years (2019 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
	2020	2019
Undiscounted lease liability cash flows due:		
Within 1 year	**2,262**	2,514
1 to 2 years	**1,672**	1,839
2 to 3 years	**1,340**	1,364
3 to 4 years	**1,025**	1,105
4 to 5 years	**878**	876
5 to 10 years	**2,192**	2,427
Over 10 years	**1,515**	1,174
	10,884	11,299
Impact of discounting	**(1,622)**	(1,577)
Lease liabilities at 31 December	**9,262**	9,722
Of which – current	**1,933**	2,067
– non-current	**7,329**	7,655

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 2020 is $5,309 million (2019 $5,688 million). The majority of this future commitment relates to the floating LNG vessel to service the Greater Tortue Ahmeyim project from 2023.

		$ million
	2020	2019
Total cash outflow for amounts included in lease liabilities[a]	**2,779**	2,709
Expense for variable payments not included in the lease liability	**41**	67
Short-term lease expense	**621**	331
Additions to right-of-use assets in the period	**1,714**	2,542
Gain on sale and leaseback transactions	**187**	—

[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 2020	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	**—**	**3,079**	**—**	**3,079**
Loans		**929**	**369**	**—**	**1,298**
Trade and other receivables	20	**20,252**	**—**	**—**	**20,252**
Derivative financial instruments	30	**—**	**10,049**	**2,698**	**12,747**
Cash and cash equivalents	25	**24,905**	**6,206**	**—**	**31,111**
Financial liabilities					
Trade and other payables	22	**(44,960)**	**—**	**—**	**(44,960)**
Derivative financial instruments	30	**—**	**(8,320)**	**(82)**	**(8,402)**
Accruals		**(5,502)**	**—**	**—**	**(5,502)**
Lease liabilities	28	**(9,262)**	**—**	**—**	**(9,262)**
Finance debt	26	**(72,664)**	**—**	**—**	**(72,664)**
		(86,302)	**11,383**	**2,616**	**(72,303)**

29. Financial instruments and financial risk factors – continued

At 31 December 2019	Note	Measured at amortized cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
					$ million
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	26	(67,724)	—	—	(67,724)
		(96,039)	7,659	(193)	(88,573)

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 gain of $367 million (2019 net loss of $129 million). Dividend income of $17 million (2019 $20 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 and hybrid bond issuance; the compliance, control, and risk management processes for these activities are managed within the treasury function. All other foreign exchange and interest rate activities within financial markets are performed within the integrated supply and trading function and are also underpinned by the compliance, control and risk management infrastructure common to the activities of bp's integrated supply and trading function. All derivative activity is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control.

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

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

(a) Market risk

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

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

(i) Commodity price risk

The group's integrated, supply and trading function 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

29. Financial instruments and financial risk factors – continued

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 (2019 $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 2020, the total foreign currency borrowings not swapped into US dollars amounted to $321 million (2019 $219 million). During the year the group issued perpetual subordinated hybrid bonds in euro, sterling and US dollars. Whilst the contractual terms of these instruments allow the group to defer coupon payments and the repayment of principal indefinitely, the group has chosen to manage the foreign currency exposure relating to the non-US dollar hybrid bonds to their respective first call periods.

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 2020 the most significant open contracts in place were for $124 million sterling (2019 $106 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 and hybrid bonds in a variety of currencies based on market opportunities, it uses derivatives to swap the economic exposure to a floating rate basis, 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 2020 was 45% of total finance debt outstanding (2019 62%). The weighted average interest rate on finance debt at 31 December 2020 was 3% (2019 3%) and the weighted average maturity of fixed rate debt was eight years (2019 five years).

The group's earnings are sensitive to changes in interest rates on the element of the group's finance debt that has been swapped to floating rates. If the interest rates applicable to these floating rate instruments were to have changed by one percentage point on 1 January 2021, it is estimated that the group's finance costs for 2021 would change by approximately $330 million (2019 $419 million).

Financial authorities in the US, UK, EU and other territories are currently undertaking reviews of key interest rate benchmarks such as the London Inter-bank Offered Rate (LIBOR) with a view to replacing them with alternative benchmarks. bp is significantly exposed to benchmark interest rate components; predominantly USD LIBOR, GBP LIBOR, EURIBOR and CHF LIBOR. Following the completion of consultation processes, these financial authorities have begun to announce the timing of both benchmark transitions and continued publication of synthetic benchmarks.

In October 2020 the International Swaps and Derivatives Association (ISDA) published its fallback protocol containing clauses to amend derivative contracts on the cessation of LIBOR should an entity and its counterparties adhere to the protocol. The protocol's pricing mechanism is at fair market value and bp has signed up to the protocol as this removes transition uncertainty for any interest rate and cross-currency interest rate swap contracts of the Group without fall-back clauses. The ISDA fallback protocol is expected to increase market activity and certainty such that corporates can finalize their plans for implementation of the transition. bp continues to monitor regulatory and market developments over the course of the transition.

In response to the cessation of the interbank offered rates (IBORs), bp has set up an internal working group to monitor market developments and manage the transition to alternative benchmark rates and is currently assessing the impact on contracts and arrangements that are linked to existing interest rate benchmarks, for example, borrowings, leases and derivative contracts. bp is also participating on external committees and task forces dedicated to interest rate benchmark reform.

(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 2020 was $1,405 million (2019 $692 million) in respect of liabilities of joint ventures and associates and $661 million (2019 $523 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. Standing credit controls and processes were augmented intra-year given heightened uncertainty from increased oil price volatility and the evolving COVID-19 pandemic. Constraints on incoming credit risks were tightened, credit reporting and frequency was enhanced from the operational to board level, and key credit risk strategies were reviewed and vetted.

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 initial 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 2020, the group had in place credit enhancements designed to mitigate approximately $5.4 billion (2019 $7.0 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	**2020**	2019
AAA to AA-	**11 %**	16 %
A+ to A-	**59 %**	51 %
BBB+ to BBB-	**8 %**	13 %
BB+ to BB-	**6 %**	7 %
B+ to B-	**13 %**	11 %
CCC+ and below	**3 %**	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
				Related amounts not set off in the balance sheet		
At 31 December 2020	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the balance sheet	Master netting arrangements	Cash collateral (received) pledged	Net amount
Derivative assets	**14,765**	**(2,019)**	**12,746**	**(2,075)**	**(386)**	**10,285**
Derivative liabilities	**(10,414)**	**2,019**	**(8,395)**	**2,075**	**—**	**(6,320)**
Trade and other receivables	**7,667**	**(3,679)**	**3,988**	**(693)**	**(122)**	**3,173**
Trade and other payables	**(7,862)**	**3,679**	**(4,183)**	**693**	**—**	**(3,490)**
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)

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 businesses, 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 $11,325 million (2019 $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 2020 for $3,460 million (2019 $4,440 million), which are secured against inventories or receivables when utilized. The facilities are held with over 25 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 2020, $5,250 million (2019 $4,755 million) of the group's trade payables subject to these arrangements were payable to LC providers, with no material exposure to any individual provider. If these facilities were not available, this could result in renegotiation of payment terms with suppliers such that settlement periods were shorter.

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

During 2020, $14 billion (2019 $8 billion) of long-term taxable bonds were issued with terms ranging from two to thirty years. In addition the group issued perpetual hybrid bonds with a US dollar equivalent value of $11.9 billion. 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 $31.1 billion at 31 December 2020 (2019 $22.5 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2020, the group had substantial amounts of undrawn borrowing facilities available, consisting of an undrawn committed $10.0 billion credit facility and $7.6 billion (2019 $7.6 billion) of standby facilities. On 1st March 2021, following an assessment of liquidity requirements, the group replaced these with new facility agreements, consisting of an undrawn committed $8.0 billion credit facility and $4.0 billion of standby facilities. The facilities are available for three and five years respectively at pre-agreed margins and are with 27 international banks, and borrowings under them would be at pre-agreed rates.

For further information on the group's sources and uses of cash see Liquidity and capital resources on page 306.

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, other than noted below, that could be of a significantly different amount or could occur earlier than the expected maturity analysis provided.

The table below shows the timing of cash outflows relating to finance debt, trade and other payables and accruals. As part of actively managing the group's debt portfolio it is possible that cash flows in relation to finance debt could be accelerated from the profile provided. As a result of the 19 March 2021 debt buy back (see Note 26 for further information) $1.9 billion equivalent of cash outflows relating to finance debt that are presented in the table with maturities of 2-8 years have occurred within one year of the balance sheet date.

								$ million
				2020				2019
	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
Within one year	**33,290**	**4,650**	**9,119**	**1,778**	43,699	5,066	10,065	2,037
1 to 2 years	**1,728**	**157**	**6,292**	**1,477**	1,937	261	6,726	1,641
2 to 3 years	**1,590**	**184**	**7,031**	**1,305**	1,465	146	7,949	1,409
3 to 4 years	**1,332**	**87**	**8,047**	**1,110**	1,409	181	7,022	1,172
4 to 5 years	**1,335**	**217**	**6,652**	**919**	1,332	108	7,554	942
5 to 10 years	**4,570**	**108**	**22,156**	**2,408**	5,863	231	23,540	1,970
Over 10 years	**4,419**	**99**	**10,008**	**1,037**	3,957	69	2,497	249
	48,264	**5,502**	**69,305**	**10,034**	59,662	6,062	65,353	9,420

[a] 2020 includes $14,569 million (2019 $16,129 million) in relation to the Gulf of Mexico oil spill, of which $13,160 million (2019 $14,501 million) matures in greater than one year.

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, whether or not hedge accounting is applied, based upon contractual payment dates. As part of actively managing the group's debt portfolio it is possible that cash flows in relation to associated derivatives could be accelerated from the profile provided. 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 or hybrid bonds. 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 $33,704 million at 31 December 2020 (2019 $24,787 million) to be received on the same day as the related cash outflows. As a result of the termination of derivatives associated with the 19 March 2021 debt buy back (see Note 26 for further information) $1.8 billion of cash outflows that are presented in the table with maturities of 2-8 years and $1.9 billion equivalent of cash inflows on the receive legs have occurred within one year of the balance sheet date.

		$ million
Cash outflows for derivative financial instruments at 31 December	**2020**	2019
Within one year	**2,384**	1,678
1 to 2 years	**1,976**	2,384
2 to 3 years	**2,017**	2,838
3 to 4 years	**3,074**	2,906
4 to 5 years	**2,582**	3,321
5 to 10 years	**15,263**	10,633
Over 10 years	**4,483**	2,224
	31,779	25,984

For further information on our derivative financial instruments, see Note 30.

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
		2020		2019
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**858**	**(694)**	81	(744)
Oil price derivatives	**1,519**	**(1,093)**	1,918	(1,478)
Natural gas price derivatives	**6,406**	**(5,489)**	6,569	(4,871)
Power price derivatives	**1,258**	**(1,037)**	1,306	(952)
Other derivatives	**7**	**—**	110	—
	10,048	**(8,313)**	9,984	(8,045)
Embedded derivatives				
Other embedded derivatives	**1**	**(7)**	—	(77)
	1	**(7)**	—	(77)
Cash flow hedges				
Currency forwards	**4**	**—**	1	(4)
Gas price futures	**—**	**—**	—	—
	4	**—**	1	(4)
Fair value hedges				
Currency swaps	**2,614**	**(82)**	344	(637)
Interest rate swaps	**80**	**—**	138	(35)
	2,694	**(82)**	482	(672)
	12,747	**(8,402)**	10,467	(8,798)
Of which – current	**2,992**	**(2,998)**	4,153	(3,261)
– non-current	**9,755**	**(5,404)**	6,314	(5,537)

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
							2020
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**153**	**9**	**3**	**2**	**2**	**689**	**858**
Oil price derivatives	**1,159**	**197**	**90**	**63**	**7**	**3**	**1,519**
Natural gas price derivatives	**1,210**	**731**	**596**	**525**	**476**	**2,868**	**6,406**
Power price derivatives	**425**	**223**	**161**	**107**	**76**	**266**	**1,258**
Other derivatives	**—**	**—**	**7**	**—**	**—**	**—**	**7**
	2,947	**1,160**	**857**	**697**	**561**	**3,826**	**10,048**

							$ 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

30. Derivative financial instruments – continued

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

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2020
Currency derivatives	(502)	(117)	(11)	(1)	—	(63)	(694)
Oil price derivatives	(1,000)	(83)	(9)	(1)	—	—	(1,093)
Natural gas price derivatives	(1,095)	(595)	(479)	(422)	(348)	(2,550)	(5,489)
Power price derivatives	(345)	(184)	(126)	(81)	(68)	(233)	(1,037)
	(2,942)	(979)	(625)	(505)	(416)	(2,846)	(8,313)

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2019
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)

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.

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2020
Fair value of derivative assets							
Level 1	48	9	15	3	5	1	81
Level 2	3,342	858	367	212	100	709	5,588
Level 3	739	546	552	520	493	3,548	6,398
	4,129	1,413	934	735	598	4,258	12,067
Less: netting by counterparty	(1,182)	(253)	(77)	(38)	(37)	(432)	(2,019)
	2,947	1,160	857	697	561	3,826	10,048
Fair value of derivative liabilities							
Level 1	(55)	(9)	(13)	(3)	(5)	(1)	(86)
Level 2	(3,577)	(809)	(263)	(136)	(41)	(79)	(4,905)
Level 3	(492)	(414)	(426)	(404)	(407)	(3,198)	(5,341)
	(4,124)	(1,232)	(702)	(543)	(453)	(3,278)	(10,332)
Less: netting by counterparty	1,182	253	77	38	37	432	2,019
	(2,942)	(979)	(625)	(505)	(416)	(2,846)	(8,313)
Net fair value	5	181	232	192	145	980	1,735

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2019
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

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**	**Currency and other**	**Total**
Fair value contracts at 1 January 2020	**71**	**28**	**(125)**	**110**	**84**
Gains (losses) recognized in the income statement	**250**	**184**	**162**	**(66)**	**530**
Sales	**—**	**—**	**—**	**(32)**	**(32)**
Settlements	**(135)**	**(22)**	**(189)**	**—**	**(346)**
Transfers out of level 3	**5**	**(43)**	**(21)**	**(1)**	**(60)**
Net fair value of contracts at 31 December 2020	**191**	**147**	**(173)**	**11**	**176**
Deferred day-one gains (losses)					**881**
Derivative asset (liability)					**1,057**

					$ 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

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2020 was a $315-million gain (2019 $250-million gain related to derivatives still held at 31 December 2019).

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 $2,808 million. This number does not include gains and losses on the change in value of contracts which are not recognized under IFRS such as transportation and storage contracts, 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 including contracts that the group has entered into to manage the foreign currency exposure relating to the non-US dollar hybrid bonds to their respective first call periods. 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 $829 million (2019 $160 million net gain and 2018 $351 million net loss), however where these gains and losses arise on derivatives hedging finance debt they 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 2020, 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

30. Derivative financial instruments – continued

- 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, 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.

(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. Henry Hub NYMEX futures are subject to daily settlement, where their fair value at the end of each day is required to be cash settled, such that the carrying amount of these hedging instruments within continuing hedge relationships is always zero at the end of each day.

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.

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 2020			
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	**4**	**(4)**	**—**
Commodity price risk			
Highly probable forecast sales	**78**	**(78)**	**—**
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	—

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		
At 31 December 2020	$ million	$ million	$ million	mmBtu
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	**4**	**—**	**162**	
Commodity price risk				
Highly probable forecast sales	**—**	**—**		**(175)**
At 31 December 2019				
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	1	(4)	150	

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

All of the nominal amount of hedging instruments at 31 December 2020 and 2019 relating to highly probably forecast capital expenditure matures within 12 months of the relevant balance sheet date. Of the nominal amount of hedging instruments at 31 December 2020 relating to highly probably forecast sales 135 mmBtu matures within 12 months and 40 mmBtu within one to two years.

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		
	2020		2019
At 31 December	Forecast capital expenditure	Forecast sales	Forecast capital expenditure
Sterling/US dollar	1.35		1.35
Euro/US dollar	—		1.11
Korean won/US dollar	1,174.47		1,115.66
Henry Hub $/mmBtu		2.88	

Fair value hedges

At 31 December 2020, 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. Note 29 outlines the group's approach to interest rate and foreign currency exchange risk management. 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. 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.

All of the fair value hedge accounting relationships currently in place are directly affected by the interest rate benchmark reform which will replace interbank offered rates (IBORs) with alternative benchmark rates as they all manage interest rate risk. The Group is significantly exposed to benchmark interest rate components; predominantly USD LIBOR, GBP LIBOR, EURIBOR and CHF LIBOR. The nominal amounts of the applicable hedging instruments represent the extent of the risk exposure bp manages for financial derivatives designated in fair value hedge relationships that is directly affected by the interest rate benchmark reform. These are disclosed in the table below. Uncertainty around the method and timing of transition from Inter-bank Offered Rates (IBORs) to alternative risk-free rates (RfRs) may impact the assessment of whether hedge accounting can be applied to certain hedging relationships. However, the temporary reliefs provided by IFRS 9 allow bp to assume that in the event that significant uncertainty around the reform arises:

- the interest rate benchmark component of fair value hedges only needs to be assessed as separately identifiable at initial designation; 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.

Judgement will be required to determine when the uncertainty arising from interest rate benchmark reform is no longer present and when the temporary reliefs no longer apply. However, at 31 December 2020 the reliefs apply and bp continues to monitor regulatory and market developments as it manages the contractual transition.

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
At 31 December 2020	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)
Fair value hedges			
Interest rate risk on finance debt	(258)	258	—
Interest rate and foreign currency risk on finance debt	(2,743)	2,549	194
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

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
At 31 December 2020	Assets	Liabilities	
Fair value hedges			
Interest rate risk on finance debt	**80**	**—**	**4,104**
Interest rate and foreign currency risk on finance debt	**2,614**	**(82)**	**23,313**
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

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.

								$ million
At 31 December 2020	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	5-10 years	Over 10 years	Total
Fair value hedges								
Interest rate risk on finance debt	**2,705**	**996**	**—**	**227**	**—**	**176**	**—**	**4,104**
Interest rate and foreign currency risk on finance debt	**737**	**1,056**	**2,039**	**3,175**	**2,804**	**8,587**	**4,915**	**23,313**
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

The table below summarizes the weighted average floating interest rate and the weighted average exchange rates in relation to the derivatives designated as hedging instruments in fair value hedge relationships at 31 December.

At 31 December		**2020**		2019
	Interest rate swaps	**Cross-currency interest rate swaps**	Interest rate swaps	Cross-currency interest rate swaps
Interest rate	**0.58 %**	**1.88 %**	2.36 %	3.27 %
Sterling/US dollar		**1.33**		1.32
Euro/US dollar		**1.14**		1.15
Canadian dollar/US dollar		**0.78**		0.87

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		
At 31 December 2020	Assets	Liabilities	Assets	Liabilities	Discontinued hedges
Fair value hedges					
Interest rate risk on finance debt	**—**	**(4,196)**	**—**	**(81)**	**(775)**
Interest rate and foreign currency risk on finance debt	**—**	**(23,253)**	**—**	**(938)**	**—**
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)	—

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	
	Highly probable forecast capital expenditure	Highly probable forecast sales	Purchase of equity[a]	Interest rate and foreign currency risk on finance debt	Total
At 1 January 2020	**(1)**	**—**	**(651)**	**(170)**	**(822)**
Recognized in other comprehensive income					
Cash flow hedges marked to market	**7**	**78**	**—**	**—**	**85**
Cash flow hedges reclassified to the income statement - hedged item affected profit or loss	**—**	**(37)**	**—**	**—**	**(37)**
Costs of hedging marked to market	**—**	**—**	**—**	**42**	**42**
Costs of hedging reclassified to the income statement	**—**	**—**	**—**	**22**	**22**
	7	**41**	**—**	**64**	**112**
Cash flow hedges transferred to the balance sheet	**6**	**—**	**—**	**—**	**6**
At 31 December 2020	**12**	**41**	**(651)**	**(106)**	**(704)**

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

[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 from the cash flow hedge reserve 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:

	2020		2019		2018	
Issued	Shares thousand	$ million	Shares thousand	$ million	Shares thousand	$ million
8% cumulative first preference shares of £1 each[a]	7,233	12	7,233	12	7,233	12
9% cumulative second preference shares of £1 each[a]	5,473	9	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	21,535,840	5,383	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	34,000	9	37,400	9	92,168	23
Issue of new shares – other	—	—	—	—	—	—
Repurchase of ordinary share capital	(120,058)	(30)	(235,951)	(59)	(50,202)	(13)
At 31 December	21,449,782	5,362	21,535,840	5,383	21,525,464	5,381
		5,383		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 2020 the company repurchased 120 million ordinary shares for a total consideration of $776 million, including transaction costs of $4 million, as part of the share repurchase programme announced on 31 October 2017. All shares purchased were for cancellation. The repurchased shares represented 0.6% of ordinary share capital. The number of shares in issue is reduced when shares are repurchased.

Treasury shares[a]

	2020		2019		2018	
	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	1,296,856	323	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	34,116	9	37,400	9	92,168	23
Shares re-issued for employee share-based payment plans	(143,322)	(36)	(167,927)	(42)	(148,732)	(37)
At 31 December	1,187,650	296	1,296,856	323	1,426,265	356
Of which – shares held in treasury by bp	1,105,157	275	1,163,077	290	1,264,732	316
– shares held in ESOP trusts	82,491	21	133,707	33	161,518	40
– shares held by bp's US share plan administrator[b]	2	—	72	—	15	—

[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 5.4% (2019 5.9% and 2018 6.9%) of the called-up ordinary share capital of the company.

During 2020, the movement in shares held in treasury by bp represented less than 0.3% (2019 less than 0.5% and 2018 less than 1.0%) 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 1 January 2020	**5,404**	**12,417**	**1,498**	**27,206**	**46,525**
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	—	—	—	—	—
Cash flow hedges transferred to the balance sheet, net of tax	—	—	—	—	—
Repurchases of ordinary share capital	**(30)**	—	**30**	—	—
Share-based payments, net of tax[b]	**9**	**167**	—	—	**176**
Share of equity-accounted entities' changes in equity, net of tax[c]	—	—	—	—	—
Issue of perpetual hybrid bonds	—	—	—	—	—
Payments on perpetual hybrid bonds	—	—	—	—	—
Tax on issue of perpetual hybrid bonds	—	—	—	—	—
Transactions involving non-controlling interests, net of tax[d]	—	—	—	—	—
At 31 December 2020	**5,383**	**12,584**	**1,528**	**27,206**	**46,701**

	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[e]	—	—	—	—	—
At 31 December 2019	5,404	12,417	1,498	27,206	46,525

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

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

[c] Principally relates to a non-controlling interest transaction entered into by Rosneft.

[d] Principally relates to the sale of interests in our UK and New Zealand retail property portfolio, for which proceeds of $0.5 billion and $0.2 billion were received respectively.

[e] Principally relates to the sale of a 49% interest in bp's retail property portfolio in Australia.

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
								Hybrid bonds	Other interest	
(14,412)	**(6,495)**	**—**	**(752)**	**(160)**	**(912)**	**73,706**	**98,412**	**—**	**2,296**	**100,708**
—	**—**	**—**	**—**	**—**	**—**	**(20,305)**	**(20,305)**	**256**	**(680)**	**(20,729)**
—	**(2,224)**	**—**	**—**	**—**	**—**	**—**	**(2,224)**	**—**	**37**	**(2,187)**
—	**—**	**—**	**31**	**60**	**91**	**—**	**91**	**—**	**—**	**91**
—	**—**	**—**	**—**	**—**	**—**	**312**	**312**	**—**	**—**	**312**
—	**—**	**—**	**—**	**—**	**—**	**71**	**71**	**—**	**—**	**71**
—	**—**	**—**	**—**	**—**	**—**	**65**	**65**	**—**	**—**	**65**
—	**—**	**—**	**7**	**—**	**7**	**—**	**7**	**—**	**—**	**7**
—	**(2,224)**	**—**	**38**	**60**	**98**	**(19,857)**	**(21,983)**	**256**	**(643)**	**(22,370)**
—	**—**	**—**	**—**	**—**	**—**	**(6,367)**	**(6,367)**	**—**	**(238)**	**(6,605)**
—	**—**	**—**	**6**	**—**	**6**	**—**	**6**	**—**	**—**	**6**
—	**—**	**—**	**—**	**—**	**—**	**(776)**	**(776)**	**—**	**—**	**(776)**
1,188	**—**	**—**	**—**	**—**	**—**	**(638)**	**726**	**—**	**—**	**726**
—	**—**	**—**	**—**	**—**	**—**	**1,341**	**1,341**	**—**	**—**	**1,341**
—	**—**	**—**	**—**	**—**	**—**	**(48)**	**(48)**	**11,909**	**—**	**11,861**
—	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(89)**	**—**	**(89)**
—	**—**	**—**	**—**	**—**	**—**	**3**	**3**	**—**	**—**	**3**
—	**—**	**—**	**—**	**—**	**—**	**(64)**	**(64)**	**—**	**827**	**763**
(13,224)	**(8,719)**	**—**	**(708)**	**(100)**	**(808)**	**47,300**	**71,250**	**12,076**	**2,242**	**85,568**
(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

32. Capital and reserves – continued

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 31 December 2017	5,343	12,147	1,426	27,206	46,122
Adjustment on adoption of IFRS 9, net of tax	—	—	—	—	—
At 1 January 2018	5,343	12,147	1,426	27,206	46,122
Profit (loss) for the year	—	—	—	—	—
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications)	—	—	—	—	—
Cash flow hedges and costs of hedging (including reclassifications)	—	—	—	—	—
Share of items relating to equity-accounted entities, net of tax[a]	—	—	—	—	—
Other	—	—	—	—	—
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	—	—	—	—
Cash flow hedges that will subsequently be transferred to the balance sheet	—	—	—	—	—
Total comprehensive income	—	—	—	—	—
Dividends	49	(49)	—	—	—
Cash flow hedges transferred to the balance sheet, net of tax	—	—	—	—	—
Repurchases of ordinary share capital	(13)	—	13	—	—
Share-based payments, net of tax[b]	23	207	—	—	230
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
Transactions involving non-controlling interests, net of tax	—	—	—	—	—
At 31 December 2018	5,402	12,305	1,439	27,206	46,352

[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
								Hybrid bonds	Other interest	
(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

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.

Non-controlling interests
Non-controlling interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to bp shareholders. Included within non-controlling interests are perpetual subordinated hybrid bonds issued by BP Capital Markets PLC, a group subsidiary, on 17 June 2020 in euro, sterling and US dollars for a US dollar equivalent amount of $11.9 billion. The hybrid bonds include redemption options exercisable at the group's discretion from June 2025 to March 2030 (the first 'call date'), on specified dates thereafter, or in the event of specific circumstances (such as a change in IFRS or tax regime) as set out in the individual terms of each issue. Coupons are fixed for an initial period up to dates from September 2025 to June 2030 at rates of 3.25% to 4.875% and reset to rates determined by the contractual terms of each instrument on certain dates thereafter. The contractual terms of the hybrid bonds allow the group to defer coupon payments and the repayment of principal indefinitely, however their terms and conditions stipulate that any deferred payments must be made in the event of an announcement of an ordinary share or parity equity dividend distribution or certain share repurchases or redemptions. As the group has the unconditional right to avoid transferring cash or another financial asset in relation to these hybrid bonds, they are classified as equity instruments and reported within non-controlling interests in the consolidated financial statements.

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
			2020
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	**(2,196)**	**9**	**(2,187)**
Cash flow hedges (including reclassifications)	**41**	**(10)**	**31**
Costs of hedging (including reclassifications)	**64**	**(4)**	**60**
Share of items relating to equity-accounted entities, net of tax	**312**	**—**	**312**
Other	**—**	**71**	**71**
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	**170**	**(105)**	**65**
Cash flow hedges that will subsequently be transferred to the balance sheet	**7**	**—**	**7**
Other comprehensive income	**(1,602)**	**(39)**	**(1,641)**

			$ 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)

33. Contingent liabilities and legal proceedings

Contingent liabilities

There were contingent liabilities at 31 December 2020 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 across the world. Various tax authorities are currently examining these returns, which contain matters that could be subject to differing interpretations of applicable tax laws and regulations. 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 and legal proceedings – 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 material cases that have a greater than remote chance of reverting to the group. In one current case in the US, the owner of facilities has filed for bankruptcy and submitted a proposed restructuring plan. It is considered possible that certain decommissioning costs associated with some of these facilities may in the future revert to bp in relation to assets previously disposed. No provision has been recognised and no reliable estimate of this potential exposure is available, however any amount which may revert is not expected to have a material impact on the group's financial position. Furthermore, as described in Provisions and contingencies within Note 1, decommissioning provisions associated with downstream facilities are not generally recognized as the potential obligations cannot be measured given their indeterminate settlement dates.

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 below. Any further outstanding Deepwater Horizon related claims are not expected to have a material impact on the group's financial performance.

Legal proceedings

Proceedings relating to the Deepwater Horizon oil spill

Introduction

BP Exploration & Production Inc. (BPXP) was lease operator of Mississippi Canyon, Block 252 in the Gulf of Mexico, where the semi-submersible rig Deepwater Horizon was deployed at the time of the 20 April 2010 explosion and fire and resulting oil spill (the Incident). Lawsuits and claims arising from the Incident were brought principally in US federal and state courts. The remaining proceedings arising from the Incident are discussed below.

Economic and Property Damages Settlement

On 22 January 2021, the United States District Court for the Eastern District of Louisiana issued an order determining the completion of all claims processing operations of the court supervised settlement programme. That settlement programme had been established to administer claims pursuant to the Economic and Property Damages Settlement (EPD Settlement) which was entered into with the plaintiffs' steering committee (PSC) acting on behalf of individual and business plaintiffs in the multi-district litigation proceedings in 2012 to resolve certain economic and property damage claims. The Court also ordered that all future issues concerning EPD Settlement claims would be considered time barred under the settlement programme and that the claims administrator should proceed to complete post-closure administrative wind down activities.

Medical Benefits Class Action Settlement

In 2012 the Medical Benefits Class Action Settlement (Medical Settlement) was entered into with the PSC. It involves payments to qualifying class members based on a matrix for certain Specified Physical Conditions (SPCs), as well as a 21-year Periodic Medical Consultation Program (PMCP) for qualifying class members. As of 31 December 2020, 1 claim remained pending determination. In total, 27,603 claims (comprising 22,833 SPC claims and 4,770 PMCP claims) have been approved for compensation totalling approximately $67 million and 9,623 claims have been denied.

The Medical Settlement also includes provisions regarding class members pursuing claims for later-manifested physical conditions (LMPCs). In order to seek compensation from bp for an LMPC, class members must file a notice with the Medical Claims Administrator within 4 years after the date of first diagnosis of the LMPC. As of 31 December 2020, there were 612 pending lawsuits brought by class members claiming LMPCs.

Other civil complaints – economic loss

Nearly all economic loss and property damage claims from individuals and businesses that either opted out of the EPD Settlement and/or were excluded from that settlement have been settled or dismissed.

The claims of 10 US-resident private plaintiffs remain in the multi-district litigation proceedings in federal district court in New Orleans. Those claims have been scheduled for a process of discovery and dispositive motions which is expected to conclude around mid-2021.

Other civil complaints – personal injury

The vast majority of post-explosion clean-up, medical monitoring and personal injury claims from individuals that either opted out of the Medical Settlement and/or were excluded from that settlement have been dismissed.

In 2019, the federal district court in New Orleans determined in a series of proceedings that 923 plaintiffs had post-explosion clean-up, medical monitoring and personal injury claims that complied with the court's prior order to show cause why their claims should not be dismissed. As a result of several subsequent dismissals, approximately 881 plaintiffs' claims remained as of 31 December 2020.

On 23 February 2021, the district court issued a Case Management Order announcing its intent to sever the personal injury cases from the multi-district litigation proceedings and staying the litigation of any punitive damages claims until plaintiffs can establish a right to compensatory damages. The district court also stated that the order severing and re-allotting these cases is forthcoming. Most cases will remain in the federal district court in New Orleans and be re-allotted among the judges of that court.

Individual securities litigation

In October 2020, bp engaged with the plaintiffs in a mediation of all remaining multi-district litigation proceedings in federal district court in Houston. 28 such actions on behalf of 115 plaintiffs remained pending on 31 December 2020. The mediation resulted in settlements of all these cases and settlement agreements have now been executed with all plaintiffs.

33. Contingent liabilities and legal proceedings – continued

Canadian class actions
Following various legal proceedings, a plaintiff seeking to assert claims under Canadian law against bp on behalf of a class of Canadian residents who allegedly suffered losses because of their purchase of bp ordinary shares and ADSs appealed the motion to dismiss the case in its entirety granted on 8 November 2019. On 20 January 2021, the Court of Appeal affirmed that dismissal.

Non-US government lawsuits
On 18 October 2012, before a Mexican Federal District Court located in Mexico City, a class action complaint was filed against BP America Production Company (BPAPC) and other bp subsidiaries. On 27 June 2018, bp answered the complaint by seeking dismissal on various grounds including that no oil reached Mexican waters or land and there was no economic or environmental harm in Mexico. There has been no material development in these proceedings during 2020 and up to the date of publication of this BP Annual Report and Form 20-F 2020 in 2021.

On 3 December 2015 and 29 March 2016, Acciones Colectivas de Sinaloa (ACS) filed two class actions (which have since been consolidated) in a Mexican Federal District Court on behalf of several Mexican states against BPXP, BPAPC, and other purported bp subsidiaries. In these class actions, plaintiffs seek an order requiring the bp defendants to repair the damage to the Gulf of Mexico, to pay penalties, and to compensate plaintiffs for damage to property, to health and for economic loss. BPXP and BPAPC opposed class certification and sought dismissal, principally on the basis that no oil reached Mexican waters or land and there was no economic or environmental harm in Mexico. The court certified the class on 25 September 2019 and bp appealed that decision including by way of constitutional challenge (amparo). The amparo action was denied on 8 October 2020 and on 18 January 2021, bp's appeal of that ruling was also denied. Class notification procedures have not yet been finally determined.

These legal actions remain at a relatively early stage and while it is not possible to predict the outcome, bp believes that it has valid defences, and it intends to defend such actions vigorously.

Other legal proceedings

FERC and CFTC matters
Following an investigation by the US Federal Energy Regulatory Commission (FERC) and the US Commodity Futures Trading Commission (CFTC) of several bp entities, the Administrative Law Judge of the FERC ruled on 13 August 2015 that bp manipulated the market by selling next-day, fixed price natural gas at Houston Ship Channel in 2008 in order to suppress the Gas Daily index and benefit its financial position. On 11 July 2016 the FERC issued an Order affirming the initial decision and directing bp to pay a civil penalty of $20.16 million and to disgorge $207,169 in unjust profits. On 10 August 2016, bp filed a request for rehearing with the FERC. On 17 December 2020, the FERC denied the rehearing request, sustaining the prior decision and ordering payment of the penalty and disgorgement amounts. bp has complied with the order but strongly disagrees with the FERC's decision and is pursuing an appeal to the US Court of Appeals.

Lead paint matters
Since 1987, Atlantic Richfield Company (Atlantic Richfield), a subsidiary★ of bp, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting and Refining and another company that manufactured lead pigment during the period 1920-1946. The plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits seek various remedies including compensation to lead-poisoned children, cost to find and remove lead paint from buildings, medical monitoring and screening programmes, public warning and education of lead hazards, reimbursement of government healthcare costs and special education for lead-poisoned citizens and punitive damages. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences. It intends to defend such actions vigorously and believes that the incurrence of liability is remote. Consequently, bp believes that the impact of these lawsuits on the group's results, financial position or liquidity will not be material.

Climate change
BP p.l.c., BP America Inc. and BP Products North America Inc. are co-defendants with other oil and gas companies in multiple lawsuits brought in various state and federal courts on behalf of various governmental and private parties. The lawsuits generally assert claims under a variety of legal theories seeking to hold the defendant companies responsible for impacts allegedly caused by and/or relating to climate change and seek remedies including payment of money and other forms of equitable relief. If such suits were successful, the cost of the remedies sought in the various cases could be substantial. All of these lawsuits remain at relatively early stages and while it is not possible to predict the outcome of these legal actions, BP believes that it has valid defences, and it intends to defend such actions vigorously.

Louisiana Coastal restoration
Six coastal parishes and the State of Louisiana have filed over 40 separate lawsuits in state courts in Louisiana against various oil and gas companies seeking damages for coastal erosion. bp entities are defendants in 17 of these cases. The lawsuits allege that the defendants' historical operations in oil fields within the Louisiana onshore coastal zone failed to comply with state permits and/or were conducted without the required coastal use permits. The plaintiffs seek unspecified statutory penalties and damages, including the costs of restoring coastal wetlands allegedly impacted by oil field operations.

In addition, four private landowners have filed separate claims in the state courts in Jefferson and Plaquemines Parishes of Louisiana for restoration damages related to alleged impacts to their marshlands associated with historic oil field operations. bp entities are defendants in two of these private landowner cases.

All of these lawsuits remain at relatively early stages and while it is not possible to predict the outcome of these legal actions, bp believes that it has valid defences, and it intends to defend such actions vigorously.

34. Remuneration of senior management and non-executive directors

Remuneration of directors

			$ million
	2020	2019	2018
Total for all directors			
Emoluments	**6**	9	8
Amounts received under incentive schemes[a]	**14**	20	16
Total	**20**	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.

Pension contributions

During 2020 one executive director participated in a UK final salary pension plan in respect of service prior to 1 April 2011. During 2020, 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 103. See also Related-party transactions on page 326.

Remuneration of directors and senior management

			$ million
	2020	2019	2018
Total for all senior management and non-executive directors			
Short-term employee benefits	**17**	30	25
Pensions and other post-retirement benefits	**2**	2	2
Share-based payments	**52**	32	32
Termination benefits	**8**	—	—
Total	**79**	64	59

Senior management comprises members of the leadership 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.

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'.

Termination benefits

Termination benefits include compensation to senior management for loss of office.

35. Employee costs and numbers

Employee costs	2020	2019	2018
			$ million
Wages and salaries[a]	**7,600**	7,497	7,931
Social security costs	**729**	733	743
Share-based payments[b]	**728**	694	669
Pension and other post-retirement benefit costs	**852**	948	1,154
	9,909	9,872	10,497

			2020			2019			2018
Average number of employees[c]	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
Upstream	**4,800**	**10,600**	**15,400**	5,800	11,000	16,800	5,900	11,500	17,400
Downstream[d]	**5,800**	**37,800**	**43,600**	5,700	37,300	43,000	6,000	36,300	42,300
Other businesses and corporate[e]	**1,800**	**7,300**	**9,100**	2,100	10,600	12,700	1,900	12,100	14,000
	12,400	**55,700**	**68,100**	13,600	58,900	72,500	13,800	59,900	73,700

[a] Includes termination costs of $1,237 million (2019 $182 million and 2018 $493 million). Reinvent bp restructuring accruals of $714 million and provisions of $428 million for employee termination payments were held at 31 December 2020.

[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 19,100 (2019 18,100 and 2018 17,100) service station staff.

[e] Includes 0 (2019 2,500 and 2018 4,000) agricultural, operational and seasonal workers in Brazil.

The reduction in the average number of employees in 2020 compared to 2019 is principally a result of the reinvent bp programme and divestment activity.

36. Auditor's remuneration

Fees	2020	2019	2018
			$ million
The audit of the company annual accounts[a]	**30**	32	25
The audit of accounts of subsidiaries of the company	**11**	11	10
Total audit	**41**	43	35
Audit-related assurance services[b]	**11**	4	4
Total audit and audit-related assurance services	**52**	47	39
Non-audit and other assurance services	**1**	1	2
Services relating to bp pension plans	**1**	1	1
	54	49	42

[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. 2020 fees include audit fees relating to the Petrochemicals disposal.

With effect from 2018, following a competitive tender process, Deloitte LLP (Deloitte) was appointed as auditor of the Company, replacing Ernst & Young LLP (EY).

2020 includes $0.5 million of additional fees for 2019. 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. Changes in audit fees subsequent to the audit tender, including matters relevant to the 2020 audit, have been reviewed and challenged by the Audit Committee, 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 $54 million (2019 $49 million and 2018 $42 million) is required to be presented as follows: audit $41 million (2019 $43 million and 2018 $35 million); other audit-related $11 million (2019 $4 million and 2018 $4 million); tax $nil (2019 $nil and 2018 $nil); and all other fees $2 million (2019 $2 million and 2018 $3 million).

37. Subsidiaries, joint arrangements and associates

The more important subsidiaries and associates of the group at 31 December 2020 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	Exploration and production, refining and marketing
BP America Production Company	100	US	Exploration and production, refining and marketing
BP Company North America	100	US	Exploration and production, refining and marketing
BP Corporation North America	100	US	Exploration and production, refining and marketing
BP Products North America	100	US	Exploration and production, refining and marketing
Standard Oil Company	100	US	Exploration and production, refining and marketing
BP Capital Markets America	100	US	Finance

Associates	%	Country of incorporation	Principal activities
Russia			
Rosneft Oil Company	19.75	Russia	Integrated oil operations

38. Condensed consolidating information on certain US subsidiaries

On June 30, 2020, bp completed the sale of all its interest in BP Exploration (Alaska) Inc., to Hilcorp Energy, and BP Exploration (Alaska) Inc. is therefore no longer a subsidiary of BP p.l.c. Accordingly, bp is no longer presenting condensed consolidating information on BP Exploration (Alaska) Inc. as a subsidiary issuer of registered securities pursuant to Rule 3-10 of Regulation S-X. BP p.l.c. will continue to fully and unconditionally guarantee the payment obligations under the BP Prudhoe Bay Royalty Trust. BP p.l.c. also fully and unconditionally guarantees securities issued by BP Capital Markets p.l.c. and BP Capital Markets America Inc., which are 100%-owned finance subsidiaries of BP p.l.c.

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 312-317.

Oil and natural gas exploration and production activities

$ million

2020

	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	31,729	—	63,803	3,431	15,526	49,736	—	44,031	6,409	214,665
Unproved properties	410	—	3,102	2,644	2,477	3,560	—	1,584	640	14,417
	32,139	—	66,905	6,075	18,003	53,296	—	45,615	7,049	229,082
Accumulated depreciation	22,501	—	37,176	3,852	14,488	42,575	—	26,246	4,282	151,120
Net capitalized costs	9,638	—	29,729	2,223	3,515	10,721	—	19,369	2,767	77,962
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	—	—	1	—	—	—	—	—	—	1
Unproved	—	—	25	2	(1)	—	—	16	—	42
	—	—	26	2	(1)	—	—	16	—	43
Exploration and appraisal costs[c]	86	—	233	127	69	168	1	265	43	992
Development	365	—	2,966	9	451	1,507	—	2,222	130	7,650
Total costs	451	—	3,225	138	519	1,675	1	2,503	173	8,685
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[d]										
Third parties	36	—	687	113	813	1,553	2	1,378	610	5,192
Sales between businesses	1,759	—	6,274	—	53	1,641	—	4,805	277	14,809
	1,795	—	6,961	113	866	3,194	2	6,183	887	20,001
Exploration expenditure	93	—	2,724	2,579	2,185	2,289	1	367	42	10,280
Production costs	636	—	2,058	102	421	817	—	875	114	5,023
Production taxes	(22)	—	57	—	140	—	—	508	12	695
Other costs (income)[e]	(130)	1	1,633	301	117	157	44	97	113	2,333
Depreciation, depletion and amortization	1,370	—	3,655	93	678	2,459	2	1,994	335	10,586
Net impairments and (gains) losses on sale of businesses and fixed assets	2,712	5	1,716	866	2,693	2,042	—	1,839	—	11,873
	4,659	6	11,843	3,941	6,234	7,764	47	5,680	616	40,790
Profit (loss) before taxation[f]	(2,864)	(6)	(4,882)	(3,828)	(5,368)	(4,570)	(45)	503	271	(20,789)
Allocable taxes	(1,344)	—	(1,125)	(682)	(1,802)	(308)	1	1,923	91	(3,246)
Results of operations	(1,520)	(6)	(3,757)	(3,146)	(3,566)	(4,262)	(46)	(1,420)	180	(17,543)
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax										
Exploration and production activities – subsidiaries (as above)	(2,864)	(6)	(4,882)	(3,828)	(5,368)	(4,570)	(45)	503	271	(20,789)
Midstream and other activities – subsidiaries[g]	(356)	44	(302)	185	104	(14)	(8)	(163)	8	(502)
Equity-accounted entities[h]	—	31	17	—	(211)	(242)	(224)	224	—	(405)
Total replacement cost profit (loss) before interest and tax	(3,220)	69	(5,167)	(3,643)	(5,475)	(4,826)	(277)	564	279	(21,696)

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes bp's 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, bp's 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 South Caucasus Pipeline, the Baku-Tbilisi-Ceyhan pipeline, the Trans Adriatic Pipeline and the Trans Anatolian Pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia.

[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 $330-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 $369 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

2020

	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	—	4,457	—	—	10,690	—	24,963	—	—	40,110
Unproved properties	—	806	—	—	108	—	4,627	—	—	5,541
	—	5,263	—	—	10,798	—	29,590	—	—	45,651
Accumulated depreciation	—	1,592	—	—	5,490	—	7,693	—	—	14,775
Net capitalized costs	—	3,671	—	—	5,308	—	21,897	—	—	30,876
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	82	—	—	82
Unproved	—	—	—	—	—	—	3,714	—	—	3,714
	—	—	—	—	—	—	3,796	—	—	3,796
Exploration and appraisal costs[d]	—	46	—	—	15	—	315	—	—	376
Development	—	404	—	—	393	—	2,594	—	—	3,391
Total costs	—	450	—	—	408	—	6,705	—	—	7,563
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	—	860	—	—	1,110	—	—	—	—	1,970
Sales between businesses	—	—	—	—	—	—	9,344	—	—	9,344
	—	860	—	—	1,110	—	9,344	—	—	11,314
Exploration expenditure	—	50	—	—	—	—	109	—	—	159
Production costs	—	188	—	—	486	—	1,387	—	—	2,061
Production taxes	—	—	—	—	216	—	4,418	—	—	4,634
Other costs (income)	—	3	—	—	5	—	236	—	—	244
Depreciation, depletion and amortization	—	412	—	—	411	—	1,532	—	—	2,355
Net impairments and losses on sale of businesses and fixed assets		119	—	—	108	—	294	—	—	521
	—	772	—	—	1,226	—	7,976	—	—	9,974
Profit (loss) before taxation	—	88	—	—	(116)	—	1,368	—	—	1,340
Allocable taxes	—	15	—	—	(41)	—	226	—	—	200
Results of operations	—	73	—	—	(75)	—	1,142	—	—	1,140
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)	—	73	—	—	(75)	—	1,142	—	—	1,140
Midstream and other activities after tax[g]	—	(42)	17	—	(136)	(242)	(1,366)	224	—	(1,545)
Total replacement cost profit (loss) after interest and tax	—	31	17	—	(211)	(242)	(224)	224	—	(405)

[a] Amounts reported for Russia in this table include bp's share of Rosneft's worldwide activities, including insignificant amounts outside Russia.

[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction, transportation operations as well as downstream and other activities 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

	Europe		North America		South America	Africa	Asia		Australasia	Total
										$ million
										2019
	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) after 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 bp's 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, bp's 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 and Australia.

[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	—	28,179	—	—	42,633
Unproved properties	—	768	—	—	93	—	1,097	—	—	1,958
	—	4,846	—	—	10,469	—	29,276	—	—	44,591
Accumulated depreciation	—	1,046	—	—	5,078	—	8,477	—	—	14,601
Net capitalized costs	—	3,800	—	—	5,391	—	20,799	—	—	29,990
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	—	177	—	—	316
Development	—	640	—	—	675	—	2,908	—	—	4,223
Total costs	—	760	—	—	694	—	3,143	—	—	4,597
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	—	—	—	—	—	—	15,012	—	—	15,012
	—	1,002	—	—	1,621	—	15,012	—	—	17,635
Exploration expenditure	—	92	—	—	43	—	73	—	—	208
Production costs	—	216	—	—	465	—	1,386	—	—	2,067
Production taxes	—	—	—	—	343	—	7,413	—	—	7,756
Other costs (income)	—	59	—	—	16	—	346	—	—	421
Depreciation, depletion and amortization	—	323	—	—	414	—	1,657	—	—	2,394
Net impairments and losses on sale of businesses and fixed assets	—	—	—	—	(42)	—	46	—	—	4
	—	690	—	—	1,239	—	10,921	—	—	12,850
Profit (loss) before taxation	—	312	—	—	382	—	4,091	—	—	4,785
Allocable taxes	—	229	—	—	245	—	811	—	—	1,285
Results of operations	—	83	—	—	137	—	3,280	—	—	3,500
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	—	3,280	—	—	3,500
Midstream and other activities after tax[g]	(6)	(13)	23	—	(72)	82	(820)	213	—	(593)
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. Amounts reported have been amended to exclude 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, transportation operations as well as downstream and other activities 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) after 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 bp's 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, bp's 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 and Australia.

[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 Bridas Corporation.

Oil and natural gas exploration and production activities – continued

	Europe		North America		South America	Africa	Asia		Australasia	Total
										$ million
										2018
	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	—	22,561	3,646	—	39,289
Unproved properties	—	657	—	—	86	—	811	26	—	1,580
	—	4,096	—	—	9,729	—	23,372	3,672	—	40,869
Accumulated depreciation	—	670	—	—	4,665	—	6,050	3,672	—	15,057
Net capitalized costs	—	3,426	—	—	5,064	—	17,322	—	—	25,812
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	393	—	—	393
Unproved	—	137	—	—	—	—	148	—	—	285
	—	137	—	—	—	—	541	—	—	678
Exploration and appraisal costs[d]	—	67	—	—	25	—	179	—	—	271
Development	—	251	—	—	575	—	3,085	212	—	4,123
Total costs	—	455	—	—	600	—	3,805	212	—	5,072
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	—	—	—	—	—	—	14,839	—	—	14,839
	—	1,114	—	—	1,792	—	14,839	353	—	18,098
Exploration expenditure	—	89	—	—	7	—	109	—	—	205
Production costs	—	207	—	—	438	—	1,324	39	—	2,008
Production taxes	—	—	—	—	361	—	7,168	94	—	7,623
Other costs (income)	—	21	—	—	55	—	594	—	—	670
Depreciation, depletion and amortization	—	290	—	—	416	—	1,514	212	—	2,432
Net impairments and losses on sale of businesses and fixed assets	—	6	—	—	—	—	47	1	—	54
	—	613	—	—	1,277	—	10,756	346	—	12,992
Profit (loss) before taxation	—	501	—	—	515	—	4,083	7	—	5,106
Allocable taxes	—	350	—	—	321	—	814	—	—	1,485
Results of operations[g]	—	151	—	—	194	—	3,269	7	—	3,621
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	—	3,269	7	—	3,621
Midstream and other activities after tax[h]	(2)	(21)	28	—	15	207	(923)	238	—	(458)
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 have been amended to exclude 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, transportation operations as well as downstream and other activities 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.

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

Movements in estimated net proved reserves

Crude oil[a b]										million barrels 2020
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia[c]		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	(62)	—	(17)	22	—	(17)	—	175	14	114
Improved recovery	—	—	24	—	—	3	—	—	—	27
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	2	—	5	—	—	11	—	18
Production	(35)	—	(125)	(8)	—	(44)	—	(137)	(5)	(355)
Sales of reserves-in-place	—	—	(351)	—	—	—	—	—	—	(351)
	(97)	—	(467)	14	5	(58)	—	48	8	(547)
At 31 December[d]										
Developed	162	—	697	37	8	116	—	1,100	34	2,154
Undeveloped	148	—	742	195	9	21	—	547	5	1,666
	309	—	1,438	232	16	137	—	1,647	38	3,819
Equity-accounted entities (bp share)[e]										
At 1 January										
Developed	—	115	—	—	291	2	3,159	—	—	3,567
Undeveloped	—	35	—	20	257	—	2,535	—	—	2,847
	—	150	—	20	548	2	5,695	—	—	6,414
Changes attributable to										
Revisions of previous estimates	—	(5)	—	6	2	1	31	—	—	35
Improved recovery	—	10	—	—	—	—	—	—	—	10
Purchases of reserves-in-place	—	—	—	—	1	—	643	—	—	644
Discoveries and extensions	—	—	—	—	17		238	—	—	255
Production	—	(18)	—	—	(21)	—	(330)	—	—	(369)
Sales of reserves-in-place	—	—	—	—	(35)		(662)	—	—	(697)
	—	(14)	—	6	(36)	1	(79)	—	—	(122)
At 31 December[f g]										
Developed	—	112	—	5	275	2	3,123	—	—	3,517
Undeveloped	—	24	—	21	237	—	2,493	—	—	2,776
	—	136	—	26	512	3	5,615	1	—	6,293
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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
At 31 December										
Developed	162	112	697	42	283	119	3,123	1,100	34	5,671
Undeveloped	148	24	742	215	246	22	2,493	548	5	4,441
	309	136	1,438	258	529	140	5,615	1,648	38	10,112

[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] Includes 37 million barrels of crude oil associated with Assets Held for Sale in Oman.

[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 393 million barrels of crude oil in respect of the 7.09% non-controlling interest in Rosneft, including 18.53 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 5,533 million barrels, comprising less than 1 million barrels each in Egypt, Vietnam, Iraq and Canada, 0 million barrels in Venezuela and 5,531 million barrels in Russia.

Movements in estimated net proved reserves – continued

million barrels

Natural gas liquids[a b]										2020
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia[c]		
Subsidiaries										
At 1 January										
Developed	8	—	229	—	2	12	—	—	4	255
Undeveloped	5	—	250	—	21	4	—	—	—	280
	13	—	479	—	23	16	—	—	4	535
Changes attributable to										
Revisions of previous estimates	(5)	—	(22)	—	—	1	—	—	(1)	(26)
Improved recovery	—	—	1	—	—	—	—	—	—	1
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production[d]	(2)	—	(31)	—	(3)	(3)	—	—	(1)	(39)
Sales of reserves-in-place	—	—	(94)	—	—	—	—	—	—	(94)
	(7)	—	(146)	—	(2)	(2)	—	—	(2)	(159)
At 31 December[e]										
Developed	7	—	115	—	2	13	—	—	2	139
Undeveloped	—	—	218	—	19	1	—	—	—	237
	7	—	333	—	21	14	—	—	2	376
Equity-accounted entities (bp share)[f]										
At 1 January										
Developed	—	5	—	—	2	11	89	—	—	107
Undeveloped	—	3	—	—	—	—	52	—	—	55
	—	7	—	—	2	11	141	—	—	162
Changes attributable to										
Revisions of previous estimates	—	1	—	—	—	3	9	—	—	12
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases of reserves-in-place	—	—	—	—	—	—	16	—	—	16
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(2)	(2)	—	—	(5)
Sales of reserves-in-place	—	—	—	—	—	—	(14)	—	—	(14)
	—	—	—	—	—	1	10	—	—	10
At 31 December[g h]										
Developed	—	6	—	—	2	12	108	—	—	129
Undeveloped	—	1	—	—	—	—	43	—	—	44
	—	7	—	—	2	12	151	—	—	172
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	8	5	229	—	4	23	89	—	4	363
Undeveloped	5	3	250	—	21	4	52	—	—	334
	13	7	479	—	25	27	141	—	4	697
At 31 December										
Developed	7	6	115	—	4	25	108	—	2	268
Undeveloped	—	1	218	—	19	1	43	—	—	281
	7	7	333	—	23	26	151	—	2	549

[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 0 million barrels of NGL associated with Assets Held for Sale in Oman.

[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] Includes 6 million barrels of NGL 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 12 million barrels of NGLs in respect of the 7.99% non-controlling interest in Rosneft.

[h] Total proved NGL reserves held as part of our equity interest in Rosneft is 151 million barrels, comprising less than 1 million barrels each in Egypt, Venezuela, Vietnam and Canada, and 151 million barrels in Russia.

Movements in estimated net proved reserves – continued

										million barrels
Total liquids[a b]										**2020**
	Europe		**North America**		**South America**	**Africa**	**Asia**		**Australasia**	**Total**
	UK	**Rest of Europe**	**US[c]**	**Rest of North America**			**Russia**	**Rest of Asia[c]**		
Subsidiaries										
At 1 January										
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	211	—	1,599	34	4,902
Changes attributable to										
Revisions of previous estimates	(67)	—	(40)	22	1	(16)	—	175	13	87
Improved recovery	—	—	25	—	—	3	—	—	—	28
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	2	—	5	—	—	11	—	18
Production[d]	(37)	—	(155)	(8)	(3)	(47)	—	(137)	(6)	(394)
Sales of reserves-in-place	—	—	(445)	—	—	—	—	—	—	(445)
	(104)	—	(613)	14	2	(60)	—	48	6	(706)
At 31 December[e]										
Developed	168	—	812	37	10	129	—	1,100	36	2,293
Undeveloped	148	—	959	195	27	22	—	547	5	1,903
	316	—	1,771	232	37	151	—	1,647	41	4,196
Equity-accounted entities (bp share)[f]										
At 1 January										
Developed	—	120	—	—	293	13	3,248	—	—	3,675
Undeveloped	—	37	—	20	257	—	2,588	—	—	2,902
	—	157	—	20	550	13	5,836	—	—	6,576
Changes attributable to										
Revisions of previous estimates	—	(4)	—	6	2	4	39	—	—	47
Improved recovery	—	10	—	—	—	—	—	—	—	10
Purchases of reserves-in-place	—	—	—	—	1	—	660	—	—	661
Discoveries and extensions	—	—	—		17		238	—	—	255
Production	—	(19)	—	—	(21)	(2)	(331)	—	—	(374)
Sales of reserves-in-place	—	(1)	—	—	(35)		(675)	—	—	(711)
	—	(14)	—	6	(36)	2	(70)	—	—	(112)
At 31 December[g h]										
Developed	—	118	—	5	277	15	3,231	—	—	3,645
Undeveloped	—	25	—	21	237	—	2,535	—	—	2,819
	—	143	—	26	514	15	5,766	1	—	6,465
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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
At 31 December										
Developed	168	118	812	42	287	144	3,231	1,100	36	5,938
Undeveloped	148	25	959	215	265	23	2,535	548	5	4,722
	316	143	1,771	258	552	166	5,766	1,648	41	10,661

[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 37 million barrels associated with Assets Held for Sale in Oman.

[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 11 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 405 million barrels of liquids in respect of the non-controlling interest in Rosneft, including 19mmboe 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 5,683 million barrels, comprising 0 million barrels in Venezuela, less than 1 million barrels each in Iraq, Canada, Egypt and Vietnam and 5,682 million barrels in Russia.

Movements in estimated net proved reserves – continued

										billion cubic feet
Natural gas[a b]										**2020**
	Europe		**North America**		**South America**	**Africa**	**Asia**		**Australasia**	**Total**
	UK	**Rest of Europe**	**US**	**Rest of North America**			**Russia**	**Rest of Asia[c]**		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	(252)	—	580	1	(362)	(26)	—	570	(9)	503
Improved recovery	1	—	545	—	—	—	—	—	—	546
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	1	—	93	28	—	263	—	386
Production[d]	(92)	—	(603)	(1)	(627)	(367)	—	(376)	(293)	(2,358)
Sales of reserves-in-place	—	—	(3,636)	—	—	—	—	—	—	(3,636)
	(342)	—	(3,114)	—	(896)	(364)	—	457	(301)	(4,561)
At 31 December[e]										
Developed	306	—	1,921	—	1,567	1,382	—	3,883	2,058	11,118
Undeveloped	51	—	3,423	—	1,964	158	—	3,641	1,029	10,267
	358	—	5,344	—	3,531	1,541	—	7,524	3,087	21,385
Equity-accounted entities (bp share)[f]										
At 1 January										
Developed	—	108	—	—	1,130	508	9,324	10	—	11,080
Undeveloped	—	56	—	6	447	—	8,067	—	—	8,576
	—	164	—	6	1,577	508	17,391	10	—	19,656
Changes attributable to										
Revisions of previous estimates	—	29	—	2	(86)	285	1,022	—	—	1,251
Improved recovery	—	8	—	—	—	—	—	—	—	8
Purchases of reserves-in-place	—	—	—	—	—	18	1,681	1	—	1,701
Discoveries and extensions	—	—	—	—	139	—	422	—	—	561
Production[d]	—	(35)	—	—	(124)	(69)	(470)	(5)	—	(703)
Sales of reserves-in-place	—	(3)	—	—	(28)	—	(1,361)	—	—	(1,393)
	—	(2)	—	2	(99)	234	1,294	(4)	—	1,426
At 31 December[g h]										
Developed	—	141	—	2	965	600	11,373	7	—	13,088
Undeveloped	—	21	—	6	513	142	7,312	—	—	7,994
	—	162	—	8	1,478	741	18,685	7	—	21,082
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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	2,413	17,391	7,078	3,389	45,601
At 31 December										
Developed	306	141	1,921	2	2,532	1,982	11,373	3,890	2,058	24,206
Undeveloped	51	21	3,423	6	2,477	300	7,312	3,641	1,029	18,260
	358	162	5,344	8	5,009	2,282	18,685	7,531	3,087	42,467

[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] Includes 1316 billion cubic feet of natural gas associated with Assets Held for Sale in Oman.

[d] Includes 158 billion cubic feet of natural gas consumed in operations, 103 billion cubic feet in subsidiaries, 55 billion cubic feet in equity-accounted entities.

[e] Includes 1,059 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 1,640 billion cubic feet of natural gas in respect of the 10.01% non-controlling interest in Rosneft including 614 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 16,324 billion cubic feet, comprising 0 billion cubic feet in Venezuela, 7 billion cubic feet in Vietnam, 420 billion cubic feet in Egypt and 15,897 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]										2020
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia[d]		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	(110)	—	60	22	(62)	(21)	—	273	11	174
Improved recovery	—	—	118	—	—	3	—	—	—	122
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	3	—	21	5	—	56	—	84
Production[e f]	(53)	—	(259)	(8)	(111)	(110)	—	(202)	(57)	(800)
Sales of reserves-in-place	—	—	(1,072)	—	—	—	—	—	—	(1,072)
	(163)	—	(1,150)	14	(152)	(123)	—	127	(46)	(1,492)
At 31 December[h]										
Developed	221	—	1,143	37	280	367	—	1,770	391	4,210
Undeveloped	157	—	1,549	195	366	50	—	1,175	182	3,673
	378	—	2,692	232	646	417	—	2,945	573	7,883
Equity-accounted entities (bp share)[h]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	1	—	7	(13)	53	216	—	—	263
Improved recovery	—	11	—	—	—	—	—	—	—	11
Purchases of reserves-in-place	—	—	—	—	1	3	949	—	—	954
Discoveries and extensions	—	—	—	—	41	—	311	—	—	352
Production[e]	—	(25)	—	—	(42)	(14)	(412)	(1)	—	(495)
Sales of reserves-in-place	—	(1)	—	—	(40)	—	(910)	—	—	(951)
	—	(15)	—	7	(53)	42	153	—	—	134
At 31 December[i j]										
Developed	—	142	—	5	443	118	5,192	1	—	5,902
Undeveloped	—	29	—	22	326	25	3,796	—	—	4,198
	—	171	—	27	769	143	8,988	2	—	10,100
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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
At 31 December										
Developed	221	142	1,143	43	724	485	5,192	1,771	391	10,112
Undeveloped	157	29	1,549	217	692	74	3,796	1,175	182	7,871
	378	171	2,692	259	1,415	560	8,988	2,946	573	17,982

[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] Includes 264 million barrels of oil equivalent associated with Assets Held for Sale in Oman.

[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 27 million barrels of oil equivalent of natural gas consumed in operations, 18 million barrels of oil equivalent in subsidiaries, 10 million barrels of oil equivalent in equity-accounted entities.

[g] Includes 194 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 687 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 124mmboe held through bp's interests in Russia other than Rosneft.

[j] Total proved reserves held as part of our equity interest in Rosneft is 8,498 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Iraq and Canada, 0 million barrels of oil equivalent in Venezuela, 1 million barrels of oil equivalent in Vietnam, 73 million barrels of oil equivalent in Egypt and 8,423 million barrels of oil equivalent in Russia.

Movements in estimated net proved reserves – continued

Crude oil[a b]										million barrels 2019
	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

Natural gas liquids[a b]										million barrels 2019
	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	8	—	266	—	2	14	—	—	5	295
Undeveloped	6	—	246	—	25	4	—	—	—	280
	14	—	511	—	27	18	—	—	5	576
Changes attributable to										
Revisions of previous estimates	—	—	(46)	—	(1)	—	—	—	—	(47)
Improved recovery	1	—	62	—	—	—	—	—	—	63
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	1	—	—	—	—	—	—	1
Production[d]	(1)	—	(33)	—	(3)	(3)	—	—	(1)	(41)
Sales of reserves-in-place	—	—	(17)	—	—	—	—	—	—	(17)
	(1)	—	(32)	—	(4)	(3)	—	—	(1)	(41)
At 31 December[e]										
Developed	8	—	229	—	2	12	—	—	4	255
Undeveloped	5	—	250	—	21	4	—	—	—	280
	13	—	479	—	23	16	—	—	4	535
Equity-accounted entities (bp share)[f]										
At 1 January										
Developed	—	4	—	—	—	7	103	—	—	114
Undeveloped	—	3	—	—	—	—	51	—	—	54
	—	7	—	—	—	7	154	—	—	169
Changes attributable to										
Revisions of previous estimates	—	—	—	—	3	5	(11)	—	—	(3)
Improved recovery	—	1	—	—	—	—	—	—	—	1
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(2)	(2)	—	—	(4)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	2	4	(13)	—	—	(7)
At 31 December[g h]										
Developed	—	5	—	—	2	11	89	—	—	107
Undeveloped	—	3	—	—	—	—	52	—	—	55
	—	7	—	—	2	11	141	—	—	162
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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
At 31 December										
Developed	8	5	229	—	4	23	89	—	4	363
Undeveloped	5	3	250	—	21	4	52	—	—	334
	13	7	479	—	25	27	141	—	4	697

[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 94 million barrels of NGL associated with Assets Held for Sale in the USA.

[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] Includes 7 million barrels of NGL 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 11 million barrels of NGLs in respect of the 7.90% non-controlling interest in Rosneft.

[h] Total proved NGL reserves held as part of our equity interest in Rosneft is 141 million barrels, comprising less than 1 million barrels in Egypt, Venezuela, Vietnam and Canada, and 141 million barrels in Russia.

Movements in estimated net proved reserves – continued

Total liquids[a b]										million barrels 2019
	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 mmboe 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

Natural gas[a b]										billion cubic feet 2019
	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

Total hydrocarbons[a b]										million barrels of oil equivalent[c] 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[j 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 mmboe 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

Natural gas liquids[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
2018	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	11	—	177	—	2	21	—	—	5	216
Undeveloped	3	—	69	—	28	—	—	—	1	102
	14	—	246	—	30	21	—	—	6	318
Changes attributable to										
Revisions of previous estimates	1	—	20	—	—	(3)	—	—	—	17
Improved recovery	—	—	16	—	—	2	—	—	—	18
Purchases of reserves-in-place	—	—	253	—	—	—	—	—	—	253
Discoveries and extensions	3	—	1	—	—	3	—	—	—	7
Production[c]	(2)	—	(25)	—	(3)	(3)	—	—	(1)	(34)
Sales of reserves-in-place	(3)	—	—	—	—	—	—	—	—	(3)
	—	—	265	—	(3)	(2)	—	—	(1)	258
At 31 December[d]										
Developed	8	—	266	—	2	14	—	—	5	295
Undeveloped	6	—	246	—	25	4	—	—	—	280
	14	—	511	—	27	18	—	—	5	576
Equity-accounted entities (bp share)[e]										
At 1 January										
Developed	—	4	—	—	—	10	82	—	—	97
Undeveloped	—	4	—	—	—	—	49	—	—	53
	—	8	—	—	—	10	131	—	—	149
Changes attributable to										
Revisions of previous estimates	—	—	—	—	—	(1)	25	—	—	23
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(1)	(2)	—	—	(4)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	(1)	—	—	—	(3)	23	—	—	19
At 31 December[f g]										
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

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

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

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

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 16 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

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

[e] Also includes 12 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[g] Includes 356 million barrels in respect of the non-controlling interest in Rosneft, including 24 mmboe held through bp's interests in Russia other than Rosneft.

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

Movements in estimated net proved reserves – continued

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

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

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

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

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 16 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

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

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

[g] Includes 283 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

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

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

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
										2020
	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]	13,900	—	64,400	4,100	6,700	12,600	—	93,500	15,900	211,100
Future production cost[b]	10,000	—	28,200	3,400	3,600	4,200	—	45,300	5,400	100,100
Future development cost[b]	800	—	12,700	1,200	1,700	1,100	—	13,300	1,900	32,700
Future taxation[c]	1,200	—	1,100	—	500	1,800	—	26,100	2,600	33,300
Future net cash flows	1,900	—	22,400	(500)	900	5,500	—	8,800	6,000	45,000
10% annual discount[d]	500	—	9,200	(200)	200	1,100	—	2,000	2,500	15,300
Standardized measure of discounted future net cash flows[e f]	1,400	—	13,200	(300)	700	4,400	—	6,800	3,500	29,700
Equity-accounted entities (bp share)[g]										
Future cash inflows[a]	—	6,300	—	—	25,100	—	214,800	—	—	246,200
Future production cost[b]	—	3,100	—	—	13,000	—	145,700	—	—	161,800
Future development cost[b]	—	500	—	—	3,300	—	20,800	—	—	24,600
Future taxation[c]	—	2,200	—	—	1,700	—	8,000	—	—	11,900
Future net cash flows	—	500	—	—	7,100	—	40,300	—	—	47,900
10% annual discount[d]	—	100	—	—	4,400	—	23,500	—	—	28,000
Standardized measure of discounted future net cash flows[h i]	—	400	—	—	2,700	—	16,800	—	—	19,900
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[j]	1,400	400	13,200	(300)	3,400	4,400	16,800	6,800	3,500	49,600

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	(21,200)	(6,000)	(27,200)
Development costs for the current year as estimated in previous year	8,700	4,100	12,800
Extensions, discoveries and improved recovery, less related costs	1,100	1,400	2,500
Net changes in prices and production cost	(51,600)	(19,200)	(70,800)
Revisions of previous reserves estimates	6,900	400	7,300
Net change in taxation	22,900	4,600	27,500
Future development costs	100	(2,700)	(2,600)
Net change in purchase and sales of reserves-in-place	(6,200)	—	(6,200)
Addition of 10% annual discount	6,300	3,400	9,700
Total change in the standardized measure during the year[k]	(33,000)	(14,000)	(47,000)

[a] The marker prices used were Brent $41.31/bbl, Henry Hub $1.94/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 $200 million.

[g] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.

[h] Non-controlling interests in Rosneft amounted to $1,600 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 2020.

[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
										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'.

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 2020, 2019 and 2018.

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
2020	**96**	**—**	**345**	**22**	**7**	**123**	**—**	**375**	**15**	**983**
2019	100	—	400	24	7	156	—	343	17	1,046
2018	101	—	385	24	7	204	—	313	17	1,051
Natural gas liquids										thousand barrels per day
2020	**5**	**—**	**79**	**—**	**7**	**8**	**—**	**—**	**2**	**101**
2019	3	—	81	—	9	8	—	—	2	104
2018	5	—	60	—	9	11	—	—	2	88
Natural gas[f]										million cubic feet per day
2020	**221**	**—**	**1,561**	**2**	**1,695**	**923**	**—**	**966**	**795**	**6,163**
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
Equity-accounted entities (bp share)										
Crude oil[e]										thousand barrels per day
2020	**—**	**50**	**—**	**—**	**54**	**1**	**903**	**—**	**—**	**1,009**
2019	—	35	—	—	56	1	955	—	—	1,047
2018	—	34	—	—	55	1	933	16	—	1,040
Natural gas liquids										thousand barrels per day
2020	**—**	**3**	**—**	**—**	**1**	**7**	**3**	**—**	**—**	**14**
2019	—	2	—	—	1	8	3	—	—	14
2018	—	2	—	—	—	6	4	—	—	12
Natural gas[f]										million cubic feet per day
2020	**—**	**61**	**—**	**—**	**286**	**92**	**1,327**	**—**	**—**	**1,765**
2019	—	56	—	—	314	87	1,279	—	—	1,736
2018	—	59	—	—	335	80	1,286	—	—	1,760

[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 2020. A 'gross' well or acre is one in which a whole or fractional working interest is owned, while the number of 'net' wells or acres is the sum of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves.

		Europe		North America		South America	Africa	Asia		Australasia	Total[b]
		UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Number of productive wells at 31 December 2020											
Oil wells[c]	– gross	**125**	**90**	**1,326**	**175**	**5,551**	**291**	**68,286**	**2,020**	**12**	**77,876**
	– net	**73**	**27**	**741**	**47**	**2,557**	**62**	**13,594**	**475**	**2**	**17,578**
Gas wells[d]	– gross	**39**	**2**	**6,405**	**238**	**1,118**	**241**	**455**	**138**	**78**	**8,714**
	– net	**8**	**1**	**3,898**	**118**	**403**	**102**	**93**	**70**	**16**	**4,709**
Oil and natural gas acreage at 31 December 2020											thousands of acres
Developed	– gross	**86**	**64**	**3,645**	**144**	**1,364**	**850**	**8,210**	**1,281**	**181**	**15,824**
	– net	**50**	**19**	**2,200**	**63**	**365**	**303**	**1,459**	**285**	**44**	**4,788**
Undeveloped[e]	– gross	**1,892**	**140**	**4,590**	**14,948**	**23,683**	**34,246**	**442,967**	**9,662**	**7,571**	**539,699**
	– net	**1,010**	**42**	**3,518**	**7,887**	**8,358**	**19,817**	**85,477**	**2,520**	**3,299**	**131,928**

[a] Based on information received from Rosneft as at 31 December 2020.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Includes approximately 6,978 gross (1,343 net) multiple completion wells (more than one formation producing into the same well bore).
[d] Includes approximately 430 gross (203 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		
2020										
Exploratory										
Productive	**—**	**—**	**1.1**	**0.8**	**—**	**0.6**	**14.3**	**0.4**	**—**	**17.2**
Dry	**—**	**—**	**1.8**	**—**	**—**	**—**	**—**	**0.2**	**—**	**2.0**
Development										
Productive	**5.3**	**3.1**	**114.6**	**0.4**	**61.7**	**4.4**	**199.1**	**40.3**	**2.0**	**430.9**
Dry	**—**	**—**	**3.0**	**—**	**1.0**	**—**	**—**	**0.6**	**—**	**4.6**
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

[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 2020. 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 2020										
Exploratory										
Gross	—	—	5.0	1.0	2.0	7.0	—	4.0	1.0	20.0
Net	—	—	3.1	0.4	0.1	3.2	—	0.8	0.4	8.0
Development										
Gross	2.0	0.7	166.0	6.0	13.0	19.0	—	198.0	2.0	406.7
Net	0.7	0.2	104.8	3.0	4.7	4.8	—	25.0	0.8	144.0

[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	2020	2019
Non-current assets			
Investments	2	**160,544**	166,256
Receivables	3	**3,174**	2,771
Defined benefit pension plan surpluses	4	**7,567**	6,588
		171,285	175,615
Current assets			
Receivables	3	**291**	135
Cash and cash equivalents		**1**	—
		292	135
Total assets		**171,577**	175,750
Current liabilities			
Payables	5	**28,011**	18,007
Non-current liabilities			
Payables	5	**28,084**	31,927
Deferred tax liabilities	6	**2,631**	2,293
Defined benefit pension plan deficits	4	**236**	202
		30,951	34,422
Total liabilities		**58,962**	52,429
Net assets		**112,615**	123,321
Capital and reserves[a]			
Profit and loss account			
Brought forward		**92,071**	96,430
Profit (loss) for the year		**(4,831)**	4,470
Other movements		**(7,519)**	(8,829)
		79,721	92,071
Called-up share capital	7	**5,383**	5,404
Share premium account		**12,584**	12,417
Other capital and reserves		**14,927**	13,429
		112,615	123,321

[a] See Statement of changes in equity on page 260 for further information.

The financial statements on pages 259-300 were approved and signed by the chief executive officer on 22 March 2021 having been duly authorized to do so by the board of directors:

Bernard Looney Chief executive officer

The parent company financial statements of BP p.l.c. on pages 259-300 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

Company statement of changes in equity[a]

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Treasury shares	Foreign currency translation reserve	Profit and loss account	Total equity
								$ million
At 1 January 2020	**5,404**	**12,417**	**1,498**	**26,509**	**(14,412)**	**(166)**	**92,071**	**123,321**
Profit (loss) for the year	**—**	**—**	**—**	**—**	**—**	**—**	**(4,831)**	**(4,831)**
Other comprehensive income	**—**	**—**	**—**	**—**	**—**	**280**	**248**	**528**
Total comprehensive income	**—**	**—**	**—**	**—**	**—**	**280**	**(4,583)**	**(4,303)**
Dividends	**—**	**—**	**—**	**—**	**—**	**—**	**(6,367)**	**(6,367)**
Repurchases of ordinary share capital	**(30)**	**—**	**30**	**—**	**—**	**—**	**(776)**	**(776)**
Share-based payments, net of tax	**9**	**167**	**—**	**—**	**1,188**	**—**	**(624)**	**740**
At 31 December 2020	**5,383**	**12,584**	**1,528**	**26,509**	**(13,224)**	**114**	**79,721**	**112,615**
At 1 January 2019	5,402	12,305	1,439	26,509	(15,767)	(366)	96,430	125,952
Profit (loss) 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

[a] See Note 8 for further information.

The parent company financial statements of BP p.l.c. on pages 259-300 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 2020 were approved and signed by the chief executive officer on 22 March 2021 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;

(h) the requirements of paragraphs 130(f)(ii), 130(f)(iii), 134(d) to 134(f) and 135(c)-135(e) of IAS 36, Impairment of Assets; and

(i) 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.

Comparative employee cost information in note 13 has been restated due the correction of an accounting error. There is no impact on the company balance sheet or the statement of changes in equity as a result of this error.

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 to the financial statements.

The areas requiring the most significant judgement and estimation in the preparation of the financial statements are the recoverability of investment carrying values and pensions. Judgements and estimates, not all of which are significant, made in assessing the impact of the COVID-19 pandemic, and climate change and the transition to a lower carbon economy on the financial statements are also set out in boxed text below. 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.

Judgements and estimates made in assessing the impact of climate change and the transition to a lower carbon economy

Climate change and the transition to a lower carbon economy were considered in preparing the financial statements. These may have significant impacts on the currently reported amounts of the company's assets and liabilities discussed below.

Impairment of investments

The energy transition is likely to impact the future prices of commodities such as oil and natural gas which in turn may affect the recoverable amount of property, plant and equipment, and goodwill in the oil and gas industry. Management's best estimate oil and natural gas price assumptions for value-in-use impairment testing were revised downwards during 2020 and the period covered extended to 2050. The revised assumptions sit within the range of external forecasts considered by management and are broadly in line with a range of transition paths consistent with the goals of the Paris climate change agreement. Impairments were recognized during 2020 on certain investments where the subsidiary company holds Upstream oil and gas properties, as a result of the lower price assumptions. See note 2 for further information.

The energy transition may also affect the future development or viability of exploration prospects. The lower price assumptions and work to develop bp's new strategy resulted in a review of the recoverability of exploration and intangible assets during 2020. Certain intangible assets were subsequently written-off, which has resulted in the company recognizing impairments against investments in subsidiary companies holding these assets.

The parent company financial statements of BP p.l.c. on pages 259-300 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

Judgements and estimates made in assessing the impact of the COVID-19 pandemic and the economic environment
In preparing the financial statements, the following areas involving judgement and estimates were identified as most relevant with regards to the impact of the COVID-19 pandemic and current economic environment.

Going concern
Liquidity and financing is managed within bp under pooled group-wide arrangements which include the company. As part of assuring the going concern basis of preparation for the company, the ability and intent of the bp group to support the company has been taken into consideration. The most recent bp group financial statements (see pages 129 to 230) continue to be prepared on a going concern basis. Forecast liquidity has been assessed at a group level under a number of scenarios and a reverse stress test performed to support the group's going concern assertion. In addition, group management of bp have confirmed that the existing intra-group funding and liquidity arrangements as currently constituted are expected to continue for the foreseeable future, being no less than twelve months from the approval of these financial statements. No material uncertainties over going concern or significant judgements or estimates in the assessment were identified. Accordingly, the company will be able to draw on support from the bp group for the foreseeable future and these financial statements have therefore been prepared on the going concern basis.

Pensions
The volatility in the financial markets during 2020 impacted the assumptions used for determining the fair value of plan assets and the present value of defined benefit obligations in the company's defined benefit pension plans. See significant estimate: pensions and Note 4 for further information.

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.

Significant judgements and estimates: recoverability of asset carrying values
Determination as to whether, and by how much, an asset, CGU, or investment holding company chain (defined as each direct subsidiary and its own investments), is impaired involves management estimates on highly uncertain matters such as the effects of inflation and deflation on operating expenses, discount rates, capital expenditure, 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. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing.

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 recognized in the profit and loss account and the carrying amounts of investments are shown in Note 2. The estimates for assumptions made in impairment tests in 2020 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 and country risk premiums. Fair value less costs of disposal discounted cash flow calculations use the post-tax discount rate. The discount rates applied in impairment tests are reassessed each year and in 2020, the pre-tax discount rate typically ranged from 7% to 15% (2019 7% to 13%) depending on the risk premium and applicable tax rate in the geographic location of the CGU.

Oil and natural gas properties
For Upstream oil and natural gas properties in subsidiaries, 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. A change in the discount rate, reserves, resources or the oil and gas price assumptions in the next financial year may result in a recoverable amount of one or more of these assets above or below the current carrying amount and therefore there is a risk of impairment reversals or charges in that period. Management consider that reasonably possible changes in the discount rate or forecast revenue, arising from a change in oil and natural gas prices and/or production could result in a material change in their carrying amounts within the next financial year.

Oil and natural gas prices
The price assumptions used for value in use impairment testing are based on those used for investment appraisal. The investment appraisal price assumptions are recommended by the senior vice president economic & energy insights after considering a range of external prices, 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.

bp sees the prospect of an enduring impact on the global economy as a result of the COVID-19 pandemic, with the potential for weaker demand for energy for a sustained period. bp's management also expects that the aftermath of the pandemic will accelerate the pace of transition to a lower carbon economy and energy system as countries seek to 'build back better' so that their economies will be more resilient in the future. As a result of all the above, bp revised its price assumptions for value-in-use impairment testing, lowering them compared to those used in 2019 and extending the period covered to 2050. A summary of the group's revised price assumptions, in real 2020 terms, is provided below. The assumptions represent management's best estimate of future prices, which sit within the range of external forecasts considered as appropriate for the purpose. They are considered by bp to be broadly in line with a range of transition paths consistent with the Paris climate goals. However, they do not correspond to any specific Paris-consistent scenario. An inflation rate of 2% (2019 2%) is applied to determine the price assumptions in nominal terms.

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

	2021	2025	2030	2040	2050
Brent oil ($/bbl)	50	50	60	60	50
Henry Hub gas ($/mmBtu)	3.00	3.00	3.00	3.00	2.75

Impairment charges were recognized in 2020 following the downward revision of the price assumptions. See Note 2 for further information. The majority of reserves and resources that support the carrying value of the company's subsidiaries holding oil and gas properties are expected to be produced over the next 10 years.

Oil and natural gas reserves

In addition to oil and natural gas prices, significant technical and commercial assessments are required to estimate oil and natural gas reserves held by the company's subsidiaries. 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 estimates of oil and natural gas reserves. bp bases its reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements.

Reserves assumptions used for value-in-use tests in the company's subsidiaries 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 or probable.

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 measured at the higher of the contract's estimated expected credit loss and the amount initially recognized less, where appropriate, cumulative amortization.

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.

The parent company financial statements of BP p.l.c. on pages 259-300 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

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.

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

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 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.This includes the derecognition of receivables for which discounting arrangements are entered into.

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.

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

Impact of new International Financial Reporting Standards
The company adopted 'Interest Rate Benchmark Reform – Phase I – Amendments to IFRS 9 'Financial instruments' and IFRS 7 'Financial instruments: Disclosures'' with effect from 1 January 2020. The adoption of 'Interest Rate Benchmark Reform – Phase I – Amendments to IFRS 9 'Financial instruments' and IFRS 7 'Financial instruments: Disclosures' 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 2020	**166,287**	**2**	**166,289**
Additions	**—**	**—**	**—**
Disposals	**(2)**	**—**	**(2)**
At 31 December 2020	**166,285**	**2**	**166,287**
Amounts provided			
At 1 January 2020	**33**	**—**	**33**
Additions	**5,710**	**—**	**5,710**
At 31 December 2020	**5,743**	**—**	**5,743**
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
At 31 December 2020	**160,542**	**2**	**160,544**
At 31 December 2019	166,254	2	166,256

At 31 December 2020, the carrying amount of the company's net assets of $112.6 billion exceeded the group's market capitalisation of $70.5 billion. This is identified by IAS 36 Impairment of Assets as an indicator that assets may be impaired.

Management's best estimate oil and natural gas price assumptions for value-in-use impairment testing were revised downwards during 2020 and the period covered extended to 2050. Management also undertook a re-assessment of expectations to extract value from certain exploration prospects as a result of a review of the group's long-term strategic plan. As a result, management performed a review of the carrying value of the company's major investments to identify potential impairment triggers, in line with the requirements of IAS 36 Impairment of Assets. Potential indicators of impairment were identified in those subsidiaries which hold, or whose own investments hold, significant Upstream assets, requiring further tests to be performed. The cash generating units assessed were considered to be each investment holding company chain (defined as each direct subsidiary and its own investments), as this is judged to be the smallest identifiable group of assets from the company's perspective that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. Further tests were performed on BP International Ltd (BPI), BP Holdings North America Ltd (BPHNA) and BP Holdings Canada Ltd.

A recoverable amount for each investment company holding chain was calculated based on the value in use cash flows from Upstream and Downstream goodwill impairment calculations, combined with additional sources of uplift in value identified. The value in use tests used the present value of pre-tax cash flows discounted using a pre-tax rate which varies depending on the country of operation of the underlying assets.

Upstream

For Upstream assets held by the company's subsidiaries, 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.

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 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 each field is computed using appropriate individual economic models and key assumptions agreed by bp management.

Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis, including operating and capital expenditure, are derived from the business segment plan. The production profiles used are consistent with the reserve and resource volumes approved as part of bp's centrally controlled process for the estimation of proved and probable reserves and total resources.

The 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.

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.

The parent company financial statements of BP p.l.c. on pages 259-300 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

2. Investments – continued

The Upstream impairment review on BPHNA assets calculated that a 10% price increase would add $1,780 million to the value of the assets, while a 10% price reduction would result in a $2,728 million reduction. A 1% increase in discount rate would likely generate a reduction in the value of assets of $796 million, while a 1% reduction in the rate would have increased the value by $1,151 million.

The Upstream impairment review on BPI assets calculated that a 10% price increase would add $2,032 million to the value of the assets, while a 10% price reduction would result in a $3,741 million reduction. A 1% increase in discount rate would likely generate a reduction in the value of assets of $1,467 million, while a 1% reduction in the rate would have increased the value by $1,365 million.

The Upstream impairment review on BP Holdings Canada assets calculated that a 10% price increase would add $574 million to the value of the assets, while a 10% price reduction would result in a $574 million reduction. A 1% increase in discount rate would likely generate a reduction in the value of assets of $178 million, while a 1% reduction in the rate would have increased the value by $204 million.

These price sensitivity analyses do not, however, represent management's best estimate of any impairment charges or reversals that might be recognized as they do not fully incorporate consequential changes that may arise, such as changes in costs and business plans and phasing of development. For example, costs across the industry are more likely to decrease as oil and natural gas prices fall. The above sensitivity analyses therefore do not reflect a linear relationship between revenue and value that can be extrapolated. The interdependency of these inputs and risk factors plus the diverse characteristics of Upstream 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 or production volumes.

Downstream

Recoverable amounts for BPHNA also included the value of key Downstream assets held by the refinery, midstream and retail businesses. For the Downstream, 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 at an 8% pre-tax rate and aggregated with a terminal value.

Discount rates are a key assumption in the value-in-use calculations for the downstream businesses. A 1% increase in discount rate would likely generate a reduction in the value of assets of $2,200 million, while a 1% reduction in the rate would have increased the value by $2,200 million.

Other

The valuation of BPI also included the Upstream activity of the company's equity-accounted investment in Rosneft.

The BPI and BPHNA investment holding chains include the bp group's Oil and Gas trading function. These have been included in the valuation based on a multiple of underlying replacement cost profit.

Conclusions for Investment holding company chains

As a result of this review, the company has recognized total impairment charges of $5,710 million (2019 $nil) against its investments. Impairments were calculated on a value in use basis, applying discount rates of 8% to investments in North America and a weighted average rate of 11% overall. Charges of $2,565 million related to Upstream investments in Canada held through BP Holdings Canada Ltd. Impairments of $2,638 million were recognized against the BPHNA investment holding chain and $507 million against the BPI investment holding chain.

The residual value of the investment holding chains which have recognized impairment charges during the year was $138,688 million.

The more important subsidiaries of the company at 31 December 2020 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 2020 was $75,645 million (2019 $76,152 million).

3. Receivables

				$ million
	2020		2019	
	Current	Non-current	Current	Non-current
Amounts receivable from subsidiaries[a]	284	3,174	134	2,771
Amounts receivable from associates	7	—	1	—
	291	3,174	135	2,771

[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.

The parent company financial statements of BP p.l.c. on pages 259-300 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

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 and is currently under consultation for closure to future accrual. As at 31 December 2020, it 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 2020 the aggregate level of contributions was $189 million (2019 $236 million). The aggregate level of contributions in 2021 is expected to be approximately $180 million, and includes contributions we expect to be required to make by law or under contractual agreements, as well as an allowance for discretionary funding.

For the primary UK plan there is a funding agreement between the company and the trustee. On an annual basis a schedule of contributions is agreed covering the next five years. Contractually committed funding amounted to $1,014 million at 31 December 2020, 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 2020. 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 and a valuation as at 31 December 2020 is currently under way.

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		%
	2020	2019
Discount rate for pension plan liabilities	**1.4**	2.1
Rate of increase in salaries	**3.6**	3.4
Rate of increase for pensions in payment	**2.8**	2.7
Rate of increase in deferred pensions	**2.8**	2.7
Inflation for pension plan liabilities	**2.9**	2.7

Financial assumptions used to determine benefit expense		%
	2020	2019
Discount rate for pension plan service costs	**2.1**	3.0
Discount rate for pension plan other finance expense	**2.1**	2.9
Inflation for pension plan service costs	**2.6**	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		Years
	2020	2019
Life expectancy at age 60 for a male currently aged 60	**26.9**	27.3
Life expectancy at age 60 for a male currently aged 40	**28.4**	28.9
Life expectancy at age 60 for a female currently aged 60	**28.8**	28.7
Life expectancy at age 60 for a female currently aged 40	**30.4**	30.5

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

A 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.

4. Pensions – continued

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 2020, the plan switched 11% from equities to bonds (2019 2%).

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

Asset category	%
Total equity (including private equity)	**17**
Bonds/cash (including LDI)	**76**
Property/real estate	**7**

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2020 were $4,217 million (2019 $4,804 million) of government-issued nominal bonds and $24,576 million (2019 $19,462 million) of index-linked bonds.

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 269.

		$ million
	2020	2019
Fair value of pension plan assets		
Listed equities – developed markets	**5,008**	6,285
– emerging markets	**418**	1,096
Private equity[a]	**2,899**	2,675
Government issued nominal bonds[b]	**4,303**	4,884
Government issued index-linked bonds[b]	**24,576**	19,462
Corporate bonds[b]	**8,906**	6,132
Property[c]	**2,553**	2,507
Cash	**1,392**	426
Other	**795**	98
Debt (repurchase agreements) used to fund liability driven investments	**(9,387)**	(7,436)
	41,463	36,129

[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 is valued based on an analysis of recent market transactions supported by market knowledge derived from third-party valuers.

		$ million
	2020	2019
Analysis of the amount charged to profit or loss		
Current service cost[a]	**250**	227
Past service income[b]	**(48)**	2
Operating charge relating to defined benefit plans	**202**	229
Payments to defined contribution plan	**49**	42
Total operating charge	**251**	271
Interest income on plan assets[c]	**(724)**	(909)
Interest on plan liabilities	**595**	756
Other finance (income)	**(129)**	(153)
Analysis of the amount recognized in other comprehensive income		
Actual asset return less interest income on pension plan assets	**4,108**	2,945
Change in financial assumptions underlying the present value of the plan liabilities	**(4,205)**	(2,292)
Change in demographic assumptions underlying the present value of plan liabilities	**585**	136
Experience gains and losses arising on the plan liabilities	**54**	(57)
Remeasurements recognized in other comprehensive income	**542**	732

[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 income represents curtailment gains arising from 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.

4. Pensions – continued

		$ million
	2020	2019
Movements in benefit obligation during the year		
Benefit obligation at 1 January	**29,743**	26,796
Exchange adjustments	**1,302**	941
Operating charge relating to defined benefit plans	**202**	229
Interest cost	**595**	756
Contributions by plan participants[a]	**21**	20
Benefit payments (funded plans)[b]	**(1,291)**	(1,207)
Benefit payments (unfunded plans)[b]	**(6)**	(5)
Remeasurements	**3,566**	2,213
Benefit obligation at 31 December	**34,132**	29,743
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	**36,129**	32,085
Exchange adjustments	**1,583**	1,141
Interest income on plan assets[c]	**724**	909
Contributions by plan participants[a]	**21**	20
Contributions by employers (funded plans)	**189**	236
Benefit payments (funded plans)[b]	**(1,291)**	(1,207)
Remeasurements[c]	**4,108**	2,945
Fair value of plan assets at 31 December[d e]	**41,463**	36,129
Surplus at 31 December	**7,331**	6,386
Represented by		
Asset recognized	**7,567**	6,588
Liability recognized	**(236)**	(202)
	7,331	6,386
The surplus may be analysed between funded and unfunded plans as follows		
Funded	**7,564**	6,588
Unfunded	**(233)**	(202)
	7,331	6,386
The defined benefit obligation may be analysed between funded and unfunded plans as follows		
Funded	**(33,899)**	(29,541)
Unfunded	**(233)**	(202)
	(34,132)	(29,743)

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

[b] The benefit payments amount shown above comprises $1,280 million benefits (2019 $1,194 million) plus $17 million (2019 $18 million) of plan expenses incurred in the administration of the benefit.

[c] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.

[d] Reflects $41,088 million of assets held in the BP Pension Fund (2019 $35,811 million) and $306 million held in the BP Global Pension Trust (2019 $251 million), as well as $53 million representing the company's share of Merchant Navy Officers Pension Fund (2019 $53 million) and $16 million of Merchant Navy Ratings Pension Fund (2019 $14 million).

[e] The fair value of plan assets includes borrowings related to the LDI programme as described on page 268.

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 2020 for the company's plans would have had the effects shown in the table below. The effects shown for the expense in 2021 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 2021	**(275)**	**198**
Effect on pension obligation at 31 December 2020	**(5,653)**	**7,685**
Inflation rate[b]		
Effect on pension expense in 2021	**145**	**(116)**
Effect on pension obligation at 31 December 2020	**5,337**	**(4,482)**
Salary growth		
Effect on pension expense in 2021	**31**	**(27)**
Effect on pension obligation at 31 December 2020	**670**	**(585)**

[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 2021 pension expense by $28 million and the pension obligation at 31 December 2020 by $1,403 million.

The parent company financial statements of BP p.l.c. on pages 259-300 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

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 2030 and the weighted average duration of the defined benefit obligations at 31 December 2020 are as follows:

	$ million
Estimated future benefit payments	
2021	**1,070**
2022	**1,084**
2023	**1,118**
2024	**1,139**
2025	**1,133**
2026-2030	**5,929**
	Years
Weighted average duration	**19.2**

5. Payables

				$ million
		2020		2019
	Current	**Non-current**	Current	Non-current
Amounts payable to subsidiaries	**27,933**	**28,060**	17,916	31,894
Accruals	**2**	**—**	21	—
Other payables	**76**	**24**	70	33
	28,011	**28,084**	18,007	31,927

Included in current amounts payable to subsidiaries is an interest-bearing payable of $4,236 million (2019 $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 in current amounts payable is an interest-bearing payable of $5,033 million (2019 $5,031 million) with BP Finance plc. On 30 April 2020 the facility was renewed for 10 years until 30 April 2030 with interest being charged based on a 3-month USD LIBOR rate minus 0.14%. Though due in 2030, the loan is repayable to BP Finance plc at one business days notice. Non-current amounts payable to subsidiaries includes an interest-bearing payable of $27,100 million (2019 $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 liabilities of $27,933m are payable to wholly owned subsidiaries of the company within the bp group. As such, the company has control over whether these balances can be called in by the counterparties. Though the $5,033 million loan from BP Finance plc can be called at one business days notice, this loan is recorded as a non-current receivable in the financial statements of BP Finance plc, since the counterparty has no intent to call the loan at short notice. The balance of $4,236 million payable to BP International Ltd is due in December 2021, though it is the intent of management to extend this amount into a longer term loan. The company also has current liabilities of $18,652 million on Internal Funding Accounts (IFAs) payable to BP International Ltd. Whilst IFA credit balances are legally repayable on demand, in practice they have no termination date. These balances form a key part of the bp group's liquidity and funding arrangements under its centralised treasury funding model. The bp group regularly looks to optimize its funding position, as part of which management will consider whether any part of these IFA balances should be converted into longer term loans, or maintained as current payables.

The maturity profile of the financial liabilities included in the balance sheet at 31 December is shown in the table below. These amounts are included within payables.

		$ million
	2020	2019
Due within		
1 to 2 years	**30**	48
2 to 5 years	**27,259**	31,499
More than 5 years	**795**	380
	28,084	31,927

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6. Taxation

Tax charge included in total comprehensive income	2020	$ million 2019
Deferred tax		
Origination and reversal of temporary differences in the current year	338	389
This comprises:		
Taxable temporary differences relating to pensions	338	389
Deferred tax		
Deferred tax liability		
Pensions	2,631	2,293
Net deferred tax liability	2,631	2,293
Analysis of movements during the year		
At 1 January	2,293	1,907
Charge (credit) for the year in the income statement	44	55
Charge (credit) for the year in other comprehensive income	294	331
At 31 December	2,631	2,293

At 31 December 2020, deferred tax assets of $375 million on other temporary differences; $12 million relating to pensions, $75 million relating to income losses and $288 million relating to other deductible temporary differences (2019 $391 million relating to other deductible temporary differences, $67 million relating to income losses and $9 million relating to pensions) were not recognised as it is not considered probable that suitable taxable profits will be available in the company from which the future reversal of the underlying temporary differences can be deducted. There is no fixed expiry date for the unrecognised temporary differences.

7. Called-up share capital

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

	2020		2019	
Issued	Shares thousand	$ million	Shares thousand	$ million
8% cumulative first preference shares of £1 each[a]	7,233	12	7,233	12
9% cumulative second preference shares of £1 each[a]	5,473	9	5,473	9
		21		21
Ordinary shares of 25 cents each				
At 1 January	21,535,840	5,383	21,525,464	5,381
Issue of new shares for the scrip dividend programme	—	—	208,927	52
Issue of new shares for employee share-based payment plans	34,000	9	37,400	9
Repurchase of ordinary share capital	(120,058)	(30)	(235,951)	(59)
At 31 December	21,449,782	5,362	21,535,840	5,383
		5,383		5,404

[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 2020 the company repurchased 120 million ordinary shares at a cost of $776 million, including transaction costs of $4 million, as part of the share repurchase programme announced on 31 October 2017. All shares purchased were for cancellation. The repurchased shares represented 0.6% of ordinary share capital.

The parent company financial statements of BP p.l.c. on pages 259-300 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

7. Called-up share capital – continued

Treasury shares[a]

	2020		2019	
	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,296,856**	**323**	1,426,265	356
Purchases for settlement of employee share plans	**—**	**—**	1,118	—
Issue of new shares for employee share-based payment plans	**34,116**	**9**	37,400	9
Shares re-issued for employee share-based payment plans	**(143,322)**	**(36)**	(167,927)	(42)
At 31 December	**1,187,650**	**296**	1,296,856	323
Of which - shares held in treasury by bp	**1,105,157**	**275**	1,163,077	290
- shares held in ESOP trusts	**82,491**	**21**	133,707	33
- shares held by bp's US plan administrator[b]	**2**	**—**	72	—

[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 5.4% (2019 5.9%) of the called-up ordinary share capital of the company.

During 2020, the movement in shares held in treasury by bp represented less than 0.3% (2019 less than 0.5%) of the ordinary share capital of the company.

8. Capital and reserves

See statement of changes in equity for details of all reserves balances.

Share capital

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

Share premium account

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

Capital redemption reserve

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

Merger reserve

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

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 $23,600 million (2019 $24,107 million), the distribution of which is limited by statutory or other restrictions.

The financial statements for the year ended 31 December 2020 do not reflect the dividend announced on 2 February 2021 which will be paid in March 2021; this will be treated as an appropriation of profit in the year ended 31 December 2021.

9. Financial guarantees

The company has issued guarantees under which the maximum aggregate liabilities at 31 December 2020 were $80,891 million (2019 $78,586 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. See note 33 in the consolidated group financial statements of BP p.l.c. for further information.

The parent company financial statements of BP p.l.c. on pages 259-300 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

10. Share-based payments

Effect of share-based payment transactions on the company's result and financial position

		$ million
	2020	2019
Total expense recognized for equity-settled share-based payment transactions	**491**	433
Total (credit) expense recognized for cash-settled share-based payment transactions	**(13)**	(1)
Total expense recognized for share-based payment transactions	**478**	432
Closing balance of liability for cash-settled share-based payment transactions	**1**	17
Total intrinsic value for vested cash-settled share-based payments	**—**	16

Additional information on the company's share-based payment plans is provided in Note 11 to the consolidated financial statements.

11. Auditor's remuneration

Note 36 to the consolidated financial statements provides details of the remuneration of the company's auditor on a group basis.

12. Directors' remuneration

		$ million
Remuneration of directors	**2020**	2019
Total for all directors		
Emoluments	**6**	9
Amounts awarded under incentive schemes[a]	**14**	20
Total	**20**	29

[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 103.

13. Employee costs and numbers

		$ million
Employee costs[a]	**2020**	2019
Wages and salaries	**814**	597
Social security costs	**119**	107
Pension costs	**90**	80
	1,023	784

Average number of employees	**2020**	2019
Upstream	**312**	279
Downstream	**1,213**	1,142
Other businesses and corporate	**2,307**	2,300
	3,832	3,721

[a] Comparative information has been restated due the correction of an accounting error.

The employee costs noted above relate to those employees with contracts of employment in the name of BP p.l.c.. These costs are borne by other undertakings within the group.

The parent company financial statements of BP p.l.c. on pages 259-300 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

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 2020 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 3008, Australia
Advance Petroleum Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC 3008, 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	Skogarhlid 12, 105, Reykjavik, Iceland
Air BP Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Air BP Norway AS	Tjuvholmen allé, Oslo, 0252, 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]	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
Allgreen Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC 3008, 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 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 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	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

The parent company financial statements of BP p.l.c. on pages 259-300 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

Amoco Norway Oil Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Oil Holding Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Olefins Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Overseas Exploration Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Pipeline Asset Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Pipeline Holding Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Properties Incorporated	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	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, 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 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 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 Resources Limited	Level 17, 717 Bourke Street, Docklands VIC 3008, 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
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%)[g]	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 Electridad, S.L. (75.00%)	Atraque Punta Lucero, Explanada Punta Ceballos s/n, Ziérbena (Vizcaya), Spain
Baltimore Ennis Land Company, Inc.	4400 Easton Commons Way , Suite 125, Columbus OH 43219, United States
BASS Management Pty Ltd (51.00%)	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
BASS NZ Head Trust (51.00%)	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
BASS NZ Management Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
BASS NZ Sub Management Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
BASS NZ Sub Trust (51.00%)	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
BE LAMBDA-ENA GmbH	Donau-City-Straße 7, 1220, Wien, Austria
Black Lake Pipe Line Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP - Castrol (Thailand) Limited (59.81%)[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[i]	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

The parent company financial statements of BP p.l.c. on pages 259-300 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 (China) Industrial Lubricants Limited[b]	No.9 Bin Jiang South Road, Petrochemical Industrial Park, Taicang Gangkou Development Zone, Jiangsu Province, China
BP (Gibraltar) Limited[j]	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[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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[i]	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 Ofis Park K:3 , Icerenky - Atasehir, Istanbul, 34752, Turkey
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 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 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 Asia Pacific Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Asia Pacific Pte Ltd[i]	7 Straits View #26-01, Marina One East Tower, Singapore, 018936, Singapore
BP Australia Employee Share Plan Proprietary Limited	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
BP Australia Group Pty Ltd[e]	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
BP Australia Investments Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
BP Australia Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
BP Australia Shipping Pty Ltd[k]	Level 17, 717 Bourke Street, Docklands VIC 3008, 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/S, Hydrantvej 16, 2770 Kastrup, Denmark
BP Aviation Infrastructure Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
BP Benevolent Fund Trustees Limited[i]	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 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 North America LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Biofuels Trading Comércio, Importação e Exportação Ltda. (48.27%)	Avenida das Nações Unidas, 12.399 , 4º andar, cj. 41B, sala 01, São 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[l]	Level 17, 717 Bourke Street, Docklands VIC 3008, 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
BP Business Service Centre KFT[b]	BP Business Service Centre KFT, 32-34 Soroksári út, H-1095 Budapest, Hungary

The parent company financial statements of BP p.l.c. on pages 259-300 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 Solutions India Private Limited	71 & 73, 7th Floor, Maker Maxity Bandra Kurla Complex, Bandra (East), Bandra Suburban, Mumbai, 400051, India
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[i]	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 CCUS UK LTD	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Central Pipelines LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Chemical Remediation Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Chemicals East China 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 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]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Containment Response Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Containment Response System Holdings LLC[b]	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	Orestads Boulevard 73, 2300, Kobenhavn S, 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[d]	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 Retail LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
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[c]	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

The parent company financial statements of BP p.l.c. on pages 259-300 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 (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
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 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 3008, 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	Tjuvholmen allé, Oslo, 0252, 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	PwC Tower, A4 Rangoon Lane, Cantonments City, PMB CT 42 Cantonments, Accra, Ghana
BP Global Investments Limited[i]	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, 13th Floor, 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]	No 833, South Guang Zhou Avenue, Haizhu District, Guangzhou Province , China

The parent company financial statements of BP p.l.c. on pages 259-300 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 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%)[p]	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[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Holdings Central Europe B.V.	Überseeallee 1, 20457 , Hamburg, Federal Republic of Germany, Germany
BP Holdings International B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Holdings North America Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Hong Kong Limited	Unit 25-150, 25/f, Two Harbour Square, 180 Wai Yip Street, Kwun Tong, Kowloon, 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[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP International Services Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
BP Investment Management Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Investments Asia Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Iran Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Iraq N.V.	Langerbruggekaai 18, 9000 Gent, 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	19th Floor, 302, Teheran-ro, Gangnam-gu, Seoul, Korea, Republic of
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[i]	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%)[q]	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%)[r]	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 3008, 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

The parent company financial statements of BP p.l.c. on pages 259-300 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 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[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pensions (Overseas) Limited[i]	Albert House, South Esplanade, St. Peter Port, GY1 1AW, Guernsey
BP Pensions Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Petrochemicals India Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Petroleo y Gas, S.A.	Av. Francisco de Miranda, 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.	2405 York Road, Ste 201, Lutherville Timonium MD 21093-2264, United States
BP Properties Limited[i]	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 3008, Australia
BP Regional Australasia Holdings Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
BP Retail Properties Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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 Espana, S.A. Unipersonal[c]	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 3008, 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

The parent company financial statements of BP p.l.c. on pages 259-300 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 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	The Financial Services, Bishop's Court Hill, St. Michael, Barbados
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[i]	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 Fatima Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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 Beacon Holding LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Wind Energy Empire Holding LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
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 Xiaoju New Energy (Shenzhen) Co., Ltd. (70.00%)	Room 201, Complex A, Qianwan Road 1, Qianhai Shenzhen-Hong Kong Cooperation Zone, Shenzhen City, PRC
BP+Amoco International Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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
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 Gathering Holdings LLC[b]	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 3008, Australia
Britannic Energy Trading Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Britannic Investments Iraq Limited	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[t]	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
Burmah Castrol Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Burmah Castrol PLC[i]	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
Burmah Castrol South Africa (Pty) Limited[u]	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, South Africa
Burmah Chile SpA	Av. Américo Vespucio Sur No. 100, of. 1101, Las Condes, Santiago, Chile
BXL Plastics Limited[v]	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 25-150, 25/f, Two Harbour Square, 180 Wai Yip Street, Kwun Tong, Kowloon, Hong Kong
Castrol (Ireland) Limited	One Spencer Dock, North Wall Quay, Dublin 1, Ireland

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14. Related undertakings of the group – continued

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
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 3008, Australia
CASTROL Austria GmbH	Straße 6, Objekt 17, Industriezentrum NÖ-Süd,, 2355 Wr. Neudorf, Austria
Castrol B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Castrol Belgium B.V.	Langerbruggekaai 18, 9000 Gent, Belgium
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 CEE spółka z ograniczoną odpowiedzialnością	ul. Grzybowska 62, 00-844, Warszawa, Poland
Castrol Colombia Ltda.	Calle 81, No 11 - 42, Oficina 901, Torre Sur, Bogota, Colombia
Castrol Del Peru S.A.	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 Holdings Europe B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Castrol Holdings International Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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	Bucharest, District 3, Boulevard Comeliu Coposu, no 6-8, Unirii View Building, Office 101, floor 1, Romania
Castrol 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
Castrol Namibia (Pty) Limited	24 Orban Street, Klein Windhoek, Windhoek, Namibia
Castrol Nederland B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
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 Singapore PTE. Limited	7 Straits View #26-01, Marina-One East Tower, 018936, Singapore
Castrol Switzerland GmbH	Baarerstrasse 139, 6300 Zug, Switzerland
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 3008, Australia
Charge Your Car Limited[c]	Breckland, Linford Wood, Milton Keynes, MK146GY, United Kingdom
Chargemaster (Europe) GmbH	Wittener Straße 45, 44789 Bochum, Germany
Chargemaster Limited	Breckland, Linford Wood, Milton Keynes, MK146GY, United Kingdom
Charging Solutions Limited	55 Baker Street, London, W1U 7EU, 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 3008, 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
Coro Trading NZ Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
Cuyama Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Dermody Petroleum Pty. Ltd.	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
DHC Solvent Chemie GmbH	Timmerhellstsr. 28, 45478, Mülheim/Ruhr, Germany
Dome Beaufort Petroleum Limited	240 - 4th Avenue SW, Calgary AB T2P 4H4, Canada
Dome 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
ECM Markets SA (Pty) Ltd (75.00%)	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, South Africa
Elektromotive Limited	Breckland, Linford Wood, Milton Keynes, MK146GY, United Kingdom
Elite Customer Solutions Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC 3008, 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
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
Exmoor Nominee Limited (51.00%)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom

The parent company financial statements of BP p.l.c. on pages 259-300 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

Exmoor Properties GP Limited (51.00%)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Exmoor Properties PF LP (51.00%)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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
Finite Carbon Corporation (80.50%)	435 Devon Park Drive, Suite 700, Wayne, Pennsylvania, 19087, United States
Finite Resources, Inc. (80.50%)	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
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
Fotech Group Limited[a]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Fotech Solutions (Canada) Ltd.	240-Fourth Avenue SW, Calgary AB T2P 4H4 Canada
Fotech USA, LLC	1999 Bryan St., STE 900, Dallas TX 75201, United States
Fowler I Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
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
Fowler Ridge 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
Fuelplane- Sociedade Abastecedora De Aeronaves, Unipessoal, Lda	Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal
FWK (2017) Limited (In Liquidation)	55 Baker Street, London, W1U 7EU, United Kingdom
FWK Holdings (2017) Ltd (In Liquidation)	55 Baker Street, London, W1U 7EU, 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	Calle 80 No.11-42 Oficina 901, Bogota, 110111, Colombia
Grampian Aviation Fuelling Services Limited (In Liquidation)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Guangdong Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Hangzhou BP Xiaoju New Energy Co., Ltd. (70.00%)	Room 1536, Building 2, Taimei International Building, Qiantang New District, Hangzhou City, Zhejiang Province
Highlands Ethanol, LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Horizon 38 Management Company Limited (53.50%)	10 Upper Berkeley Street, London, W1H 7PE, United Kingdom
IGI Resources, Inc.	921 S. Orchard St. Ste G, Boise ID 83705, United States
Insight Analytics Solutions Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Insight Analytics Solutions Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Insight Analytics Solutions USA, Inc	2108 55th Street, Suite 105, Boulder CO 80301, United States
International Bunker Supplies Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
Iraq Petroleum Company Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Jinhua BP Xiaoju New Energy Co., Ltd. (70.00%)	Floor 1, No. 6, Panlong East Road, Fotang Town, Yiwu City, Zhejiang Province, China
Jupiter Insurance Limited	Suite 1 North, First Floor, Albert House, South Esplanade, St Peter Port, GY1 1AJ, Guernsey
Ken-Chas Reserve Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Kenilworth Oil Company Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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
Low Carbon Friends Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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
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 Gras 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

The parent company financial statements of BP p.l.c. on pages 259-300 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

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%)[b]	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 Tecnologia En Servicios Y Energia, 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
Mountain City Remediation, LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Net Zero North Sea Storage Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Net Zero Teesside Power Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
No. 1 Riverside Quay Proprietary Limited	Level 17, 717 Bourke Street, Docklands VIC 3008, Australia
Nordic Lubricants A/S	Orestads Boulevard 73, 2300, Kobenhavn S, 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
OnSight Analytics Solutions India Private Ltd.	Office No. 306, Regus Business Center , 3rd Floor, Abbusali St, Saligramam, Chennai, Tamil Nadu, 600093, India
Onyx Insight Korea Co., Ltd.	504-ho, 213-3, Cheomdan-ro, Jeju-si, Jeju-do, Korea, Republic of
OOO BP STL[b]	Novinskiy blvd.8, 18th floor, office 14, 121099, Moscow, Russian Federation
Orion Delaware Mountain Wind Farm LP[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, 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
Pacroy (Thailand) Co., Ltd. (39.50%)	23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa Sathon, Bangkok 10120, Thailand
Pearl River Delta Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Phoenix Petroleum Services, Limited Liability Company	Royal Tulip Al Rasheed Hotel, Baghdad Tower, PO Box 8070, Baghdad, Iraq
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 Castrol Indonesia (68.30%)	Perkantoran Hijau Arkadia, Tower B 9th Floor, Jl. Let. Jenderal TB. Simatupang Kav. 88, Jakarta12520, 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, Jakarta12520, Indonesia
RAPI SA (62.51%)	1, Proteos & 51, Anapafseos str, 15235 Vrilissia, Attica, Greece
Remediation Management Services Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Richfield Oil Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Rolling Thunder I Power Partners, LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
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 (In Liquidation)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Saturn Insurance Inc.	400 Cornerstone Drive, Suite 240, Williston VT 05495, United States
Shanghai Quanzhi New Energy Co., Ltd. (70.00%)	No. 399 Dongfeng highway, Dongping Town, Chongming District, Shanghai City, (Dongping Economic Development, China
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 Dépots 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%)[w]	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
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
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 Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Stryde International Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
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
Suzhou BP Xiaoju New Energy Co., Ltd. (70.00%)	Room 703, Building 32, No.258 Shengpu Road, Suzhou Industrial Park, China

The parent company financial statements of BP p.l.c. on pages 259-300 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

Taradadis Pty. Ltd.	Level 17, 717 Bourke Street, Docklands VIC 3008, 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[i]	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
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
Warrenville Development Limited Partnership[b]	33 North LaSalle Street, Chicago, Illinois 60602, United States
Water Way Trading and Petroleum Services LLC	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 3008, 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
Zhuhai BP Xiaoju New Energy Co., Ltd. (70.00%)	Room 105-72746 (Centralized office area), No.6 Baohua Road, Hengqin New District, Zhuhai City, China

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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%)[h]	1 More London Place, London, SE1 2AF, United Kingdom
Advanced Biocatalytics Corporation (24.50%)[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 Vijfhuizerweg 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
Alyssum Group Ltd (26.23%)[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%)	Sitio Canto, número S/N, bairro / distrito Zona Rural, município Russas - CE, CEP 62900-000, Brazil
Aragonesa de Gestión de Energías Alternativas, SL (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
ATAS Anadolu Tasfiyehanesi Anonim Sirketi (68.00%)[x]	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
Australasian Lubricants Manufacturing Company Pty Ltd (50.00%)[h]	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%)[y]	Mw1 Building 557 Shoreham Road, Heathrow Airport, London,TW6 3RT, United Kingdom
Axion Comercializacion De Combustibles Y Lubricantes S.A. (50.00%)	Luis A de Herrera 1248, Torre II, Piso 22 (Edificio World Trade Center), Montevideo, Uruguay
Axion Energy Argentina S.A. (50.00%)	Carlos María Della Paolera 265, Piso 22, Ciudad Autónoma de Buenos Aires, Argentina
Axion Energy Holding S.L. (50.00%)[b]	Arbea Campus Empresarial, Edifico 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%)[h]	Maples & Calder, P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
Azerbaijan International Operating Company (30.37%)[z]	190 Elgin Avenue, George Town, Grand Cayman , KY1-9005, Cayman Islands
Baplor S.A. (50.00%)	Colonia 810, Oficina 403, Montevideo, Uruguay
Barranca Sur Minera S.A. (50.00%)	Calle 14, No 781, Piso 2, Oficina 3, Ciudad de La Plata, Provincia de Buenos Aires, Argentina
Beer Energien GmbH & Co. KG (50.00%)[f]	Saganer Straße 31, 90475 Nürnberg, Germany
Beer GmbH (50.00%)	Saganer Straße 31, 90475 Nürnberg, Germany
Belenos s.r.l. (32.48%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Bellflower Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Belmont Technology Inc. (26.10%)	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Bighorn Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Bighorn Solar Class B, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Bighorn Solar Construction, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States

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14. Related undertakings of the group – continued

Bighorn Solar Holdings 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Bighorn Solar Holdings 2, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Bighorn Solar Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Billund Refuelling I/S (50.00%)	GA Centervej 1, DK-7190, Billund, Denmark
Birch Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Blackbear Alabama Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Blackbear Alabama Solar Land Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Blendcor (Pty) Limited (37.50%)[γ]	135 Honshu Road, Islandview, Durban, 4052, South Africa
Blue Marble Holdings Limited (23.58%)[α]	Northgate House, 2nd Floor, Upper Borough Walls, Bath, BA1 1RG, United Kingdom
Blue Ocean Seismic Services Limited (23.33%)[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 Bioenergia Campina Verde Ltda. (48.27%)	Rua Principal, Fazenda Recanto, Zona Rural, Caixa Postal 01, Ituiutaba, Minas Gerais, 38.300-898, Brazil
BP Bioenergia Ituiutaba Ltda. (48.27%)	Fazenda Recanto, Zona Rural, CEP 38.300-898, Ituiutaba, Minas Gerais, Brazil
BP Bioenergia Itumbiara S.A. (48.27%)	Estrada Municipal Itumbiara / Chacoeira Dourada, Fazenda Jandaia, Gleba B, Itumbiara, Goiás, 75516-126, Brazil
BP Bioenergia Tropical S.A. (48.27%)	Rodovia GO 410, km 51 à esquerda, Fazenda Canadá, s/n, Zona Rural, Edéia, Goiás, 75940-000, Brazil
BP Bunge Bioenergia S.A. (48.27%)	Avenida das Nações Unidas, nº 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 Gangkou 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 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 SPG Energy Trading Co., Ltd. (49.00%)	Room 8309, Floor 3, Yufanghailian Office Building, No. 1 Indian Ocean Road, West Coast Comprehensive Bonded Area, Qingdao Division of the PRC (Shandong) , China
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-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%)[h]	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
Braendstoflageret Kobenhavns Lufthavn I/S (20.83%)[f]	Københavns, Lufthavn, 2770 Kastrup, Denmark
Brechin Castle Solar Limited (49.97%)	48-50 Sackville Street, Port of Spain, Trinidad and Tobago
Briar Creek Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
BTC International Investment Co. (30.10%)[β]	Maples & Calder, P.O. Box 309, Ugland 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
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-İdari Bina sit. No:25 A/1, Konyaaltı, Antalya, Turkey
Central African Petroleum Refineries (Pvt) Ltd (20.75%)	Block 1Tendeseka 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 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
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
Compatibleglobe, Lda (49.97%)	Rua Sousa Martins, no 10, 1050 218, Lisboa, Portugal

The parent company financial statements of BP p.l.c. on pages 259-300 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

Concessionaria Stalvedro SA (50.00%)	San Gottardo Sud, 6780, Airolo, Switzerland
Continental Divide Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Continental Divide Solar II, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Continental Divide Solar Land Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Cottontail Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Cottontail Solar 2, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Cottontail Solar 3, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Cottontail Solar 4, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Cottontail Solar 5, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Cottontail Solar 6, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Cottontail Solar 7, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
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, 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, 4050-324, Porto, Portugal
Dinarel S.A. (20.00%)	La Cumparsita 1373, piso 4°, 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
El Temsah Petroleum Company "PETROTEMSAH" (25.00%)	5 El Mokhayam El Daiem St, 6th Sector, Nasr City, Egypt
Elk Hill Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Elk Hill Solar 2, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Elk Hill Solar 2 Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Elm Branch Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
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 Alcala numero 63, 28014, Madrid, Spain
Energy Emerging Investments, LLC (50.00%)[b]	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Entrepot petrolier de Chambery (32.00%)	562 Avenue du Parc de l'Ile, 92000, NANTERRE, France
Entrepôt Pétrolier de Puget sur Argens - EPPA (58.25%)	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 Capital Private Limited (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
Field Services Enterprise S.A. (50.00%)	Av. Leandro N. Alem 1180, piso 11°, Buenos Aires, Argentina
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 (26.23%)	60 Sloane Avenue, London, SW3 3XB, United Kingdom
Flytanking AS (50.00%)	Postboks 36, Stjordal, NO-7501, Norway
Foreseer Ltd (25.00%)	121A Thoday Street, Cambridge , Cambridgeshire, CB1 3AT , United Kingdom
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
Free Power for Schools 13 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Free Power for Schools 14 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Free Power for Schools 15 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Free Power for Schools 17 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

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14. Related undertakings of the group – continued

Free Power for Schools 19 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Free Power for Schools 4 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Free Power for Schools 5 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Free Power for Schools 6 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Free Power for Schools 7 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Freetricity Central June Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Freetricity Commercial June Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
FreeWire Technologies, Inc. (28.18%)	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Fresh-Serve Bakeries LLC (44.27%)[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 Alcala numero 63, 28014, Madrid, Spain
Fuerzas Energéticas del Sur de Europa XIX, SL (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
Fuerzas Energéticas del Sur de Europa, S.L. (49.97%)	Calle Alcala 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
Gardermeon 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 Infraestrutura S.A. (27.96%)	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%)[z]	190 Elgin Avenue, George Town, Grand Cayman , KY1-9005, Cayman Islands
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]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Glade Solar Class B, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Glade Solar Construction Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Glade Solar Construction, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Glade Solar Holdings 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Glade Solar Holdings 2, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Glade Solar Holdings, LLC (24.99%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Land Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
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
Great Ropemaker Partnership (G.P.) Limited (50.00%)[y]	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 Limited (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, 238463, Singapore
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
Happy Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
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
Heliex 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, Zhenzhou City
HFS Hamburg Fuelling Services GbR (50.00%)[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 No 1, Carretera Fuencarral a Alcobendas (M-603), km 3.8, Alcobendas, Madrid, Spain

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14. Related undertakings of the group – continued

Howbery Solar Park Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Impact Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Impact Solar Class B, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Impact Solar Construction, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Impact Solar Holdings 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Impact Solar Holdings 2, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Impact Solar Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Implantación de Fuentes Energéticas de Origen Renovable, SL (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
In Salah Gas Limited (25.50%)[y]	IFC 5, St Helier, Jersey, JE1 1ST, Jersey
In Salah Gas Services Limited (25.50%)[y]	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%)[h]	PCJ Building36 Trafalgar Road, Kingston 10, Jamaica
Johnson Corner Solar I, LLC (24.99%)[b]	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware 19902, United States
Kala Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, 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
Lensky Nefteprovod Limited Liability Company (20.00%)	Pervomayskaya str, 32a, Republic of Saha (Yakytya), 678144, city of Lensk, Lenskiy region, Russian Federation
LFS Langenhagen Fuelling Services GbR (50.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
Lightning Systems, Inc. (35.30%)[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 2HU, United Kingdom
Lightsource Asset Holdings (Europe) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
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 2HU, 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 2HU, United Kingdom
Lightsource Asset Holdings 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Asset Holdings 3 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, 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 2HU, 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 Limited (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Lightsource Beacon 2, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Lightsource Beacon Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Lightsource Beacon, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Lightsource Bodegas 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Bodegas 3 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Bodegas 4 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
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 Cicero (CE 153), S/N, KM 58, Lima Campos, Ico, Ceara, 63.435-000, Brazil
Lightsource Bom Lugar IX Geração de Energia Ltda. (49.97%)	Fazenda Terra Nova, located at Rod. Padre Cicero (CE 153), S/N, KM 58, Lima Campos, Ico, Ceara, 63.435-000, Brazil
Lightsource Bom Lugar V Geração de Energia Ltda. (49.97%)	Fazenda Terra Nova, located at Rod. Padre Cicero (CE 153), S/N, KM 58, Lima Campos, Ico, Ceara, 63.435-000, Brazil
Lightsource Bom Lugar VI Geração de Energia Ltda. (49.97%)	Fazenda Terra Nova, located at Rod. Padre Cicero (CE 153), S/N, KM 58, Lima Campos, Ico, Ceara, 63.435-000, Brazil
Lightsource Bom Lugar VII Geração de Energia Ltda. (49.97%)	Fazenda Terra Nova, located at Rod. Padre Cicero (CE 153), S/N, KM 58, Lima Campos, Ico, Ceara, 63.435-000, Brazil
Lightsource Bom Lugar VIII Geração de Energia Ltda. (49.97%)	Fazenda Terra Nova, located at Rod. Padre Cicero (CE 153), S/N, KM 58, Lima Campos, Ico, Ceara, 63.435-000, Brazil

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14. Related undertakings of the group – continued

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%)[γ]	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Brasil Energia Renovável Ltda (49.97%)	Avenida Bernardino de Campos 98, 12th floor, room 38, suite A, Paraiso, Sao Paulo, 04004-040, Brazil
Lightsource Brasil Energia Renovável Particições S.A. (49.97%)	Avenida Bernardino de Campos 98, 12th floor, room 38, suite A, Paraiso, Sao Paulo, 04004-040, 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 2HU, United Kingdom
Lightsource Construction Management Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, 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 Elk Hill 2 Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Elk Hill Solar 2 Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, 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 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Finca 3 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, 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 Greece SPV 1 Single Member S.A. (49.97%)	280 Kifissias Ave, 152 32 Halandri, Anthens, Greece
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 Iberia Project Holdings 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 2HU, 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 2HU, United Kingdom
Lightsource India Limited (25.49%)[h]	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
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 Australia Pty Limited (49.97%)	C/- Baker McKenzie, Level 19, 181 William Street, Melbourne VIC 3000, Australia
Lightsource Labs Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Labs Limited (49.97%)	Trinity House, Charleston Road, Ranelagh, Dublin 6, D06C8X4, Ireland
Lightsource Largescale Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Manzanilla Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Midscale Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Milagres I Geração de Energia Ltda. (49.97%)	Sítio Cajueiro - Abaiara - left of BR 116, KM491, Caatinga Grande, Zona Rural, Abaiara, 63.240-000, Brazil
Lightsource Milagres II Geração de Energia Ltda. (49.97%)	Sítio Cajueiro - Abaiara - left of BR 116, KM491, Caatinga Grande, Zona Rural, Abaiara, 63.240-000, Brazil
Lightsource Milagres III Geração de Energia Ltda. (49.97%)	Sítio Cajueiro - Abaiara - left of BR 116, KM491, Caatinga Grande, Zona Rural, Abaiara, 63.240-000, Brazil
Lightsource Milagres IV Geração de Energia Ltda. (49.97%)	Sítio Cajueiro - Abaiara - left of BR 116, KM491, Caatinga Grande, Zona Rural, Abaiara, 63.240-000, Brazil
Lightsource Milagres V Geração de Energia Ltda. (49.97%)	Sítio 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

The parent company financial statements of BP p.l.c. on pages 259-300 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 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 Poland Holdings (UK) 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 2HU, United Kingdom
Lightsource Radiate 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, 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, United Kingdom
Lightsource Renewable Energy Asset Holdings 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Lightsource Renewable Energy Asset Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Lightsource Renewable Energy Asset Management Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Lightsource Renewable Energy Asset Management, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Lightsource Renewable Energy Australia Holdings Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Renewable Energy Cariñena S.L. (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
Lightsource Renewable Energy Development, LLC (49.97%)[b]	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware 19902, United States
Lightsource Renewable Energy Garnacha, S.L. (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
Lightsource Renewable Energy Greece Holdings (UK) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
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%)	815-816 International Trade Tower, Nehru Place, New Delhi 110019, Delhi, 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
Lightsource Renewable Energy Italy Finco s.r.l. (49.97%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
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 11 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 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

The parent company financial statements of BP p.l.c. on pages 259-300 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 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 2HU, 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 (HoldCo), Lda (49.97%)	Rua Sousa Martins, no 10, 1050 218, Lisboa, Portugal
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]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Lightsource Renewable Energy Services, Inc. (49.97%)	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Lightsource Renewable Energy Spain Development, SL (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
Lightsource Renewable Energy Spain Holdings, SL (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
Lightsource Renewable Energy Spain SPV 1, SL (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
Lightsource Renewable Energy Trading, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Lightsource Renewable Energy Trading, SL (49.97%)	C/Pradillo 5, Bajo Exterior Derecha, 28002, Madrid, Spain
Lightsource Renewable Energy US Assets, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
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 2HU, United Kingdom
Lightsource Residential NI Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
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 2HU, 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, 018981, Singapore
Lightsource Singapore Renewables Private Limited (49.97%)	8 Marina Boulevard, #05-02, Marina Bay Financial Centre, 018981, 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 2HU, United Kingdom
Lightsource SPV 101 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, 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 2HU, United Kingdom
Lightsource SPV 109 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 112 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 114 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 115 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 116 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 118 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 123 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 126 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 127 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 128 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 130 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 133 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

The parent company financial statements of BP p.l.c. on pages 259-300 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 135 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 138 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 140 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 142 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 143 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 145 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 149 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 151 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 152 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 154 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 155 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 156 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 160 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 162 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 166 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 167 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 169 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 170 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 171 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 174 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 175 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 176 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 179 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 18 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 180 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 182 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 183 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 184 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 185 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 187 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 189 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 19 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 191 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 192 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 196 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 199 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 20 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 200 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 201 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 202 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 203 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 204 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 205 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 206 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 212 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 213 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 214 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 215 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 216 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 217 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 221 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 222 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 223 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 224 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 232 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 233 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 234 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 235 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 236 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

The parent company financial statements of BP p.l.c. on pages 259-300 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 239 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 242 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 243 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 244 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 245 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 246 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 247 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 248 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 249 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 25 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 251 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 252 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 253 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 254 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 258 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 259 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 26 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 261 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 262 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 263 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 264 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 265 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 266 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 267 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 268 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 269 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 270 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 271 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 272 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 273 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 274 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 275 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 276 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 277 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 278 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 279 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 280 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 281 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 282 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 283 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 284 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 285 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom
Lightsource SPV 286 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 29 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 32 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 35 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 39 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 40 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 41 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 42 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 44 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 47 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 49 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 5 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 50 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 54 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 56 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 60 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 69 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

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14. Related undertakings of the group – continued

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 2HU, 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 2HU, 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 2HU, United Kingdom
Lightsource SPV 91 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 92 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 98 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, 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 2HU, United Kingdom
Lightsource Trinidad Holdings (UK) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Viking 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Viking 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Xenium 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Xenium 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, 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
LREHL Renewables India SPV 1 Private Limited (25.49%)	815-816 International Trade Tower, Nehru Place, 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 FinCo 2 Pty Limited (49.97%)	Level 19 'CBW', 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]	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware 19902, United States
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
Malmo Fuelling Services AB (33.33%)	Box 22, SE 230 32 Malmö-Sturup, Sweden
Manchester Airport Storage and Hydrant Company Limited (25.00%)	One Bartholomew Close , London, EC1A 7BL, 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
Maverick Solar Class B, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Maverick Solar Construction, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Maverick Solar Holdings 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Maverick Solar Holdings 2, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Maverick Solar Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
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
Mediteranean 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
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
Modelos Energéticos Sostenibles, S.L. (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
MTS Francis Court Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

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14. Related undertakings of the group – continued

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 Trevemper 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
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 Victor 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 Nº 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%)[y]	Arbea Campus Empresarial, Edifico 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 Nº 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, Edifico 1. Ctra de Fuencarral a Alcobendas, M603, KM 3,8 28108 Alcobendas, MADRID, SPAIN
Pan American Fueguina S.A. (50.00%)	O´Higgins N° 194, Rio Grande, Argentina
Pan American Sur S.A. (50.00%)	O´Higgins N° 194, Rio Grande, Argentina
Parque Eolico Del Sur S.A. (27.50%)	Av. Leandro N. Alem 1180, piso 11°, Buenos Aires, Argentina
Peninsular Aviation Services Company Limited (50.00%)[i]	P O Box 6369, Jeddah21442, Saudi Arabia
Pentland Aviation Fuelling Services Limited (50.00%)[c]	Suite 44 (C/O Best4Business Accountants), Beaufort Court, Admirals Way, London, E14 9XL, United Kingdom
Petrostock SA (50.00%)	route de Pré-Bois 2, 1214, Vernier, Switzerland
Pharaonic Petroleum Company "PhPC" (25.00%)	70/72 Road 200, Maadi, Cairo, Egypt
Pollon s.r.l. (32.48%)	Via Giacomo Leopardi 7, CAP 20123, Milan, Italy
Pont Andrew Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
POPLAR SOLAR 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
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, Brazil
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
Rahamat Petroleum Company (PETRORAHAMAT) (50.00%)	70/72 Road 200, Maadi, Cairo, Egypt
Raststaette Glarnerland AG, Niederurnen (20.00%)	Nideracher 1, 8867, Niederurnen, Switzerland
RD Petroleum Limited (49.00%)	399 Moray Place, Dunedin, 9016, New Zealand
Reliance BP Mobility Limited (49.00%)	3rd Floor, Maker Chambers IV, 222, Nariman Point, Mumbai, 400 021, India
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

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14. Related undertakings of the group – continued

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%)[γ]	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%)[h]	1 Refinery Road, Prospecton, 4110, South Africa
Shell Mex and B.P. Limited (40.00%)[γ]	Shell Centre, London, SE1 7NA, United Kingdom
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
SKA Energy Holdings Limited (50.00%)	LOB 16, Suite #309, Jebel Ali Free Zone, Dubai, PO BOX 262794, United Arab Emirates
SM Realisations Limited (In Liquidation) (40.00%)	Shell International Petroleum, Co Ltd, Shell Centre, 8 York Road, London, SE1 7NA , United Kingdom
Société d'Avitaillement et de Stockage de Carburants Aviation "SASCA" (40.00%)[b]	1 Place Gustave Eiffel, 94150, RUNGIS, France
Société de Gestion de Produits Pétroliers - SOGEPP (37.00%)	27 Route du Bassin Numéro 6, 92230, GENNEVILLIERS, France
Solar Photovoltaic (SPV2) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Solar Photovoltaic (SPV3) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
South Caucasus Pipeline Company Limited (28.83%)[γ]	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
Srednelenskoye Limited Liability Company (49.00%)	Kosmodamianskaya embarkment, 52 bldg 3, floor 9, unit 29, 115035, Moscow, Russian Federation
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%)	Jenfelder Allee 80, 22039, Hamburg, Germany
Stockholm Fuelling Services Aktiebolag (25.00%)	Box 7, 190 45 Arlanda, Sweden
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%)	Zwüscheteich, 8153, Rümlang, Switzerland
TAU Tanklager Auhafen AG (50.00%)	Auhafenstrasse 10a, 4132, Muttenz, Switzerland
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
Terminal de Combustiveis Paulinia S.A. (50.00%)	Avenida Paris, 4077, Suite 3, Cascata, Paulínia, São Paulo State, 13046-061, Brazil
Terminales Canarios, S.L. (50.00%)	Carretera de San Andréss/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
TGH Tankdienst-Gesellschaft Hamburg GbR (66.67%)[f]	Sportallee 6, 22335 Hamburg, Germany
TGHL Tanklager-Gesellschaft Hannover-Langenhagen GbR (50.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
TGK Tanklagergesellschaft Koln-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%)[β]	Maples & Calder, P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands

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14. Related undertakings of the group – continued

The Consolidated Petroleum Company Limited (50.00%)[γ]	Shell Centre, London, SE1 7NA, United Kingdom
The Consolidated Petroleum Supply Company Limited (50.00%)[δ]	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 (44.27%)[b]	Corporation Service Company, 421 West Main Street, Frankfort KY 40601, United States
Thorntons LLC (44.27%)[b]	CSC, 251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
TLK Holding Company LLC (44.27%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
TLK Intermediate Holding Company LLC (44.27%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
TLK Operating Company LLC (44.27%)[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
Trans Adriatic Pipeline AG (20.00%)	Lindenstrasse 2, 6340 Baar, Switzerland
TransTank GmbH (50.00%)	Am Stadthafen 60, 45881 Gelsenkirchen, Germany
Tuwale Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
TWQE2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Ubiworx Systems Designated Activity Company (49.97%)	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, New 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, Brazil
Vendimia Grid, AIE (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
Ventress Solar Farm 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Verde Grande Geração de Energia Ltda. (49.97%)	Fazenda Contendas na Rodovia Joaquim de Freitas, sentido Mato Verde a Catut, Km 2 à direita, Zona Rural, município de Mato Verde-MG, CEP 39527-000, Brazil
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, Argentina
Vientos Sudamericanos Chubut Norte IV S.A. (24.50%)	Lavalle 190, piso 6 Depto L, Buenos Aires, Argentina
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
Wellington North Solar Farm Pty Limited (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
West Wyalong FinCo Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
West Wyalong Fund Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
West Wyalong HoldCo 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
West Wyalong HoldCo 2 Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
West Wyalong Trust (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Whitetail Solar 1, LLC (24.99%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Whitetail Solar 2, LLC (24.99%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Whitetail Solar 3, LLC (24.99%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Whitetail Solar 6, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Whitetail Solar Land Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Wick Farm Grid Limited (24.99%)	Woodwater House, Pynes Hill, Exeter, EX2 5WR, United Kingdom
Wildflower Solar 1, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Wildflower Solar Land Holdings, LLC (49.97%)[b]	251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
Wiri Oil Services Limited (27.78%)	Ross Pauling & Partners Limited, 106b Bush Road, Albany, Auckland, 0632, New Zealand
Woolooga FinCo Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Woolooga Fund Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Woolooga HoldCo 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Woolooga HoldCo 2 Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Woolooga Trust (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
Your Power No. 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Your Power No. 10 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Your Power No. 19 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

The parent company financial statements of BP p.l.c. on pages 259-300 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Your Power No. 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Your Power No. 3 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Your Power No. 8 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Your Power No12 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Zonneweide 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] 100% ordinary shares and 58.65% preference shares
[x] 15% held directly by BP p.l.c
[y] B shares
[z] Unlimited redeemable shares
[α] 96.52% C shares
[β] 1.89% A shares and 40.80% B shares
[γ] 49.97% A shares, 50.00% C shares, 50.00% D shares, 50.00% E shares, 49.95% F shares and 50.00% G shares
[δ] 5% held directly by BP p.l.c

The parent company financial statements of BP p.l.c. on pages 259-300 do not form part of bp’s Annual Report on Form 20-F as filed with the SEC.

Additional disclosures

Selected financial information

This information has been extracted or derived from the audited consolidated financial statements of the bp group. Note 1 to the financial statements includes details on the basis of preparation of these financial statements. The selected information should be read in conjunction with the audited financial statements and related notes. The audited consolidated financial statements and related notes as of 31 December 2020 and 2019 and for the three years ended 31 December 2020 are presented on page 130.

					$ million except per share amounts
	2020	2019	2018	2017	2016
Income statement data					
Sales and other operating revenues	**180,366**	278,397	298,756	240,208	183,008
Profit (loss) before interest and taxation	**(21,740)**	11,706	19,378	9,474	(430)
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(3,148)**	(3,552)	(2,655)	(2,294)	(1,865)
Taxation	**4,159**	(3,964)	(7,145)	(3,712)	2,467
Non-controlling interests	**424**	(164)	(195)	(79)	(57)
Profit (loss) for the year[a]	**(20,305)**	4,026	9,383	3,389	115
Inventory holding (gains) losses★, before tax	**2,868**	(667)	801	(853)	(1,597)
Taxation charge (credit) on inventory holding gains and losses	**(667)**	156	(198)	225	483
RC profit (loss)★ for the year	**(18,104)**	3,515	9,986	2,761	(999)
Net (favourable) adverse impact of non-operating items★ [b] and fair value accounting effects★ [b], before tax	**16,649**	8,263	3,380	3,730	6,746
Taxation charge (credit) on non-operating items and fair value accounting effects, and certain foreign exchange impacts on the group's tax charge for the period	**(4,235)**	(1,788)	(643)	(325)	(3,162)
Underlying RC profit★ for the year	**(5,690)**	9,990	12,723	6,166	2,585
Earnings per share[c] – cents					
Profit (loss) for the year[a] per ordinary share					
Basic	**(100.42)**	19.84	46.98	17.20	0.61
Diluted	**(100.42)**	19.73	46.67	17.10	0.60
RC profit (loss) for the year per ordinary share★	**(89.53)**	17.32	50.00	14.02	(5.33)
Underlying RC profit for the year per ordinary share★	**(28.14)**	49.24	63.70	31.31	13.79
Dividends paid per share – cents	**31.50**	41.00	40.50	40.00	40.00
– pence	**24.458**	31.977	30.568	30.979	29.418
Capital expenditure★ [d]					
Organic capital expenditure★	**12,034**	15,238	15,140	16,501	16,675
Inorganic capital expenditure★	**2,021**	4,183	9,948	1,339	777
	14,055	19,421	25,088	17,840	17,452
Balance sheet data (at 31 December)					
Total assets	**267,654**	295,194	282,176	276,515	263,316
Net assets	**85,568**	100,708	101,548	100,404	96,843
Share capital	**5,383**	5,404	5,402	5,343	5,284
bp shareholders' equity	**71,250**	98,412	99,444	98,491	95,286
Finance debt due after more than one year	**63,305**	57,237	55,803	54,873	51,073
Gearing★	**31.3%**	31.1%	30.0%	27.0%	26.5%
Ordinary share data[e]					Share million
Basic weighted average number of shares	**20,222**	20,285	19,970	19,693	18,745
Diluted weighted average number of shares	**20,222**	20,400	20,102	19,816	18,855

[a] Profit attributable to bp shareholders.

[b] See pages 304 and 305 for further analysis of these items.

[c] A reconciliation to GAAP information is provided on page 348.

[d] From 2017 onwards bp reports organic, inorganic and total capital expenditure on a cash basis which were previously reported on an accruals basis. This aligns with bp's financial framework and is consistent with other financial metrics used when comparing sources and uses of cash.

[e] The number of ordinary shares shown has been used to calculate the per share amounts.

Additional information

Capital expenditure

	2020	2019	2018
			$ million
Capital expenditure			
Organic capital expenditure	**12,034**	15,238	15,140
Inorganic capital expenditure[ab]	**2,021**	4,183	9,948
	14,055	19,421	25,088

	2020	2019	2018
			$ million
Organic capital expenditure by segment			
Upstream			
US	**3,341**	4,019	3,482
Non-US	**6,009**	7,885	8,545
	9,350	11,904	12,027
Downstream			
US	**632**	913	877
Non-US	**1,698**	2,084	1,904
	2,330	2,997	2,781
Other businesses and corporate			
US	**80**	47	54
Non-US	**274**	290	278
	354	337	332
	12,034	15,238	15,140
Organic capital expenditure by geographical area			
US	**4,053**	4,979	4,413
Non-US	**7,981**	10,259	10,727
	12,034	15,238	15,140

[a] 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 entire consideration payable of $10,268 million, after customary closing adjustments, was paid in instalments between July 2018 and April 2019. The amounts presented as inorganic capital expenditure include $3,480 million for 2019 and $6,788 million for 2018 relating to this transaction. 2018 includes $1,739 million relating to the purchase of an additional 16.5% interest in the Clair field west of Shetland in the North Sea, as part of the agreements with Conoco-Phillips in which Conoco-Philips simultaneously purchased bp's entire 39.2% interest in the Greater Kuparuk Area on the North Slope of Alaska. 2020, 2019 and 2018 also include amounts relating to the 25-year extension to our ACG production-sharing agreement★ in Azerbaijan.

[b] 2020 includes a $500 million deposit in respect of the strategic partnership with Equinor and $1 billion relating to an investment in a 49% interest in the group's Indian fuels and mobility venture with Reliance industries.

Non-operating items

Non-operating items are charges and credits included in the financial statements that bp discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers not to be part of underlying business operations and are disclosed in order to enable investors to understand better and evaluate the group's reported financial performance. An analysis of non-operating items is shown in the table below.

			$ million
	2020	2019	2018
Upstream			
Gain on sale of businesses and fixed assets[a]	**360**	143	437
Impairment and losses on sale of businesses and fixed assets[a b]	**(13,214)**	(7,036)	(527)
Environmental and other provisions	**(2)**	(32)	(35)
Restructuring, integration and rationalization costs[c]	**(401)**	(89)	(131)
Fair value gain (loss) on embedded derivatives	**—**	—	17
Other[d e]	**(2,511)**	67	56
	(15,768)	(6,947)	(183)
Downstream			
Gain on sale of businesses and fixed assets[a f]	**2,320**	50	15
Impairment and losses on sale of businesses and fixed assets[a]	**(1,136)**	(122)	(69)
Environmental and other provisions	**(33)**	(78)	(83)
Restructuring, integration and rationalization costs[c]	**(633)**	85	(405)
Fair value gain (loss) on embedded derivatives	**—**	—	—
Other	**(39)**	(12)	(174)
	479	(77)	(716)
Rosneft			
Other	**(205)**	(103)	(95)
	(205)	(103)	(95)
Other businesses and corporate			
Gain on sale of businesses and fixed assets[a]	**194**	—	4
Impairment and losses on sale of businesses and fixed assets[a g]	**(19)**	(917)	(264)
Environmental and other provisions[h]	**(177)**	(231)	(640)
Restructuring, integration and rationalization costs[c]	**(262)**	6	(190)
Fair value gain (loss) on embedded derivatives	**—**	—	—
Gulf of Mexico oil spill response	**(255)**	(319)	(714)
Other[i]	**201**	(30)	(159)
	(318)	(1,491)	(1,963)
Total before interest and taxation	**(15,812)**	(8,618)	(2,957)
Finance costs[j]	**(625)**	(511)	(479)
Total before taxation	**(16,437)**	(9,129)	(3,436)
Taxation credit (charge) on non-operating items	**4,345**	1,943	510
Taxation - impact of US tax reform[k]	**—**	—	121
Taxation - impact of foreign exchange[l]	**(99)**	—	—
Total after taxation	**(12,191)**	(7,186)	(2,805)

[a] See Financial statements – Note 4 for further information.

[b] 2020 impairment charges for Upstream include $156 million in relation to the likely disposal of an exploration asset. 2019 includes impairments charges principally resulting from the announcements to dispose of certain assets in the US and Egypt. 2018 includes an impairment reversal for assets in the North Sea and Angola.

[c] Restructuring charges are classified as non-operating items where they relate to an announced major group restructuring. A major group restructuring is a restructuring programme affecting more than one of the group's operating segments that is expected to result in charges of more than $1 billion over a defined period. 2020 includes recognized provisions for restructuring costs for plans that were formalized during the year. 2018 includes amounts related to the programme originally announced in 2014 that was completed in 2018.

[d] 2020 includes exploration write-offs of $1,974 million relating to fair value ascribed to certain licences as part of the accounting at the time of acquisition of upstream assets in Brazil, India and the Gulf of Mexico and the impairment of certain intangible assets in Mauritania and Senegal. 2018 includes exploration write-offs of $124 million 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.

[e] 2020 includes $545 million net impairments reported by equity-accounted entities.

[f] 2020 includes a gain of $2.3 billion on the sale of our petrochemicals business.

[g] 2019 includes $877 million relating to the reclassification of accumulated foreign exchange losses from reserves to the income statement upon the contribution of our Brazilian biofuels business to BP Bunge Bioenergia.

[h] All periods primarily reflect charges due to the annual update of environmental provisions, including asbestos-related provisions for past operations, together with updates of non-Gulf of Mexico oil spill related legal provisions.

[i] From 2020, BP is presenting temporary valuation differences associated with the group's interest rate and foreign currency exchange risk management of finance debt as non-operating items. These amounts represent: (i) the impact of ineffectiveness and the amortisation of cross currency basis resulting from the application of fair value hedge accounting; and (ii) the net impact of foreign currency exchange movements on finance debt and associated derivatives where hedge accounting is not applied. Relevant amounts in the comparative periods presented were not material.

[j] All periods presented include the unwinding of discounting effects relating to Gulf of Mexico oil spill payables. 2020 also includes the income statement impact associated with the buyback of finance debt. See Note 26 for further information.

[k] In 2017 the US tax reform reduced the US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018. 2018 reflects a further impact following a clarification of the tax reform. The impact of the US tax reform has been treated as a non-operating item because it is not considered to be part of underlying business operations, has a material impact upon the reported result and is substantially impacted by Gulf of Mexico oil spill charges, which are also treated as non-operating items. Separate disclosure is considered meaningful and relevant to investors.

[l] From 2020, bp is presenting certain foreign exchange effects on tax as non-operating items. These amounts represent the impact of: (i) foreign exchange on deferred tax balances arising from the conversion of local currency tax base amounts into functional currency, and (ii) taxable gains and losses from the retranslation of US dollar-denominated intra-group loans to local currency. Relevant amounts in the comparative periods presented were not material.

Non-GAAP information on fair value accounting effects

The impacts of fair value accounting effects, relative to management's internal measure of performance, and a reconciliation to GAAP information is set out below. Further information on fair value accounting effects is provided on page 344.

			$ million
	2020	2019	2018
Upstream			
Unrecognized (gains) losses brought forward from previous period[a]	253	(455)	(419)
Favourable (adverse) impact relative to management's measure of performance	(738)	706	(39)
Exchange translation gains (losses) on fair value accounting effects	—	2	3
Unrecognized (gains) losses carried forward	(485)	253	(455)
Downstream			
Unrecognized (gains) losses brought forward from previous period[a]	104	(56)	(151)
Favourable (adverse) impact relative to management's measure of performance	(149)	160	95
Unrecognized (gains) losses carried forward	(45)	104	(56)
Other businesses and corporate			
Favourable (adverse) impact relative to management's measure of performance[b]	675	—	—
Unrecognized (gains) losses carried forward	675	—	—
Favourable (adverse) impact relative to management's measure of performance – by region			
Upstream			
US	198	(179)	(35)
Non-US	(936)	885	(4)
	(738)	706	(39)
Downstream			
US	27	148	(155)
Non-US	(176)	12	250
	(149)	160	95
Other businesses and corporate			
US	—	—	—
Non-US	675	—	—
	675	—	—
	(212)	866	56
Taxation credit (charge)	(11)	(155)	12
	(223)	711	68

[a] 2018 brought forward fair value accounting effect balances include a $55-million adjustment between Upstream and Downstream as part of the transfer of the NGL business between segments.

[b] From 2020 fair value accounting effects include changes in the fair value of derivatives entered into by the group to manage currency exposure and interest rate risks relating to hybrid bonds to their respective first call periods. For further information see page 344.

Net debt including leases

Net debt including leases★ is shown in the table below.

		$ million
At 31 December	2020	2019
Net debt★	38,941	45,442
Lease liabilities	9,262	9,722
Net partner (receivable) payable for leases entered into on behalf of joint operations★	(7)	(158)
Net debt including leases	48,196	55,006
Total equity	85,568	100,708
Gearing including leases★	36.0%	35.3%

★ See Glossary

Liquidity and capital resources

Financial framework

bp has a resilient financial framework that, taken together with our strategy, creates a compelling investor proposition offering committed distributions, profitable growth and sustainable value. The framework comprises a coherent approach to capital allocation, a resilient balance sheet, a disciplined approach to investment allocation and a relentless focus on executing bp's business plan.

bp's approach to capital allocation leads to a clear set of priorities – funding our resilient dividend as the first priority, deleveraging the balance sheet, investment in low carbon★ and convenience and mobility to advance our energy transition strategy, investment in resilient hydrocarbons to generate sustainable cash flow, and then returning surplus cash★ as share buybacks. In a period of low prices, the group has the flexibility to reduce cash costs and to reduce or defer capital investment, as appropriate.

Our shareholder distribution policy reflects these priorities for the uses of cash alongside an ongoing consideration of factors, including changes in the environment, the underlying performance of the business, the outlook for the group financial framework, and other market factors which may vary quarter to quarter.

Net debt★ at 31 December 2020 was $38.9 billion and is expected to reduce in line with the receipt of divestment proceeds and the growth in operating cash flow★. bp is targeting $25 billion of proceeds by 2025 (from mid 2020), and at the end of 2020 bp had completed or agreed transactions for over half of this target.

We expect operating cash flow to cover capital expenditure★ and the dividend, with capital expenditure initially in a range of $13-15 billion, before increasing to $14-16 billion once net debt reaches $35 billion. Capital expenditure is expected to be at the lower end of the initial range in 2021. Looking further out across 2021-25, bp's cash balancing point is expected to average around $40 per barrel (assuming an average refining marker margin of around $11 and Henry Hub gas price at $3) in 2020 real terms. Gulf of Mexico oil spill payments on a post-tax basis were just over $1.6 billion in 2020 and are expected to be around $1 billion in 2021.

In 2020, the return on average capital employed★ was (3.8)%[a] at an average of $42 per barrel. The return on average capital employed is targeted to grow to 12-14% by 2025 at $50 to 60 per barrel in 2020 real terms, and assuming bp planning assumptions, as we continue to execute our strategy. This is supported by an expected 7-9% growth in earnings before interest, tax, depreciation and amortization (compound annual growth rate) across the same period and subject to the same price and planning assumptions.

[a] Nearest equivalent GAAP measures: Numerator – Loss attributable to bp shareholders $(20.3); Denominator – Average capital employed $163.3 billion.

Dividends and other distributions to shareholders

The dividend is determined in US dollars, the economic currency of bp, and the dividend level is reviewed by the board each quarter. The quarterly dividend was reset to 5.25 cents per ordinary share per quarter as part of a wider distribution policy announced in August 2020, and is intended to remain fixed at this level.

The total dividend distributed to bp shareholders in 2020 was $6.4 billion (2019 $8.3 billion). This dividend was all paid in cash as shareholders no longer have the option to receive a scrip dividend in place of receiving cash.

Included in the distribution policy is a commitment that, once net debt reaches $35 billion and subject to maintaining a strong investment grade credit rating, at least 60% of surplus cash will be distributed to shareholders through share buybacks.

The share buyback programme to offset the dilutive impact of the legacy scrip dividend concluded in January 2020 and purchased 120 million ordinary shares in 2020 at a cost of $776 million (2019 $1.5 billion), including fees and stamp duty.

Financing the group's activities

The group's principal commodities, oil and gas, are priced internationally in US dollars. Group policy has generally been to minimize economic exposure to currency movements by financing operations with US dollar debt. Where debt and hybrid bonds are issued in other currencies, they are generally swapped back to US dollars using derivative contracts, or else hedged by maintaining offsetting cash positions in the same currency. Cash balances of the group are mainly held in US dollars or swapped to US dollars and holdings are well diversified to reduce concentration risk. The group is not, therefore, exposed to significant currency risk regarding its cash or borrowings. Also see Risk factors on page 67 for further information on risks associated with prices and markets and Financial statements – Note 29.

The group's finance debt at 31 December 2020 amounted to $72.7 billion (2019 $67.7 billion). Of the total finance debt, $9.4 billion is classified as short term at the end of 2020 (2019 $10.5 billion). See Financial statements – Note 26 for more information on the short-term balance. Net debt★ was $38.9 billion at the end of 2020, a decrease of $6.5 billion from the 2019 year-end position of $45.4 billion.

On 17 June 2020, a group subsidiary★ issued perpetual subordinated hybrid bonds in EUR, GBP and USD for a US dollar equivalent amount of $11.9 billion. As the group has the unconditional right to avoid transferring cash or another financial asset in relation to these hybrid bonds, they are classified as equity instruments and reported within non-controlling interests.

The ratio of finance debt to finance debt plus total equity at 31 December 2020 was 45.9% (2019 40.2%). Gearing was 31.3% at the end of 2020 (2019 31.1%). See Financial statements – Note 27 for finance debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt.

Cash and cash equivalents of $31.1 billion at 31 December 2020 (2019 $22.5 billion) are included in net debt. We manage our cash position so that the group has adequate cover to respond to potential short-term market liquidity, short term price environment volatility and expect to maintain a robust cash position.

The group also has an undrawn committed $8 billion credit facility and undrawn committed bank facilities of $4 billion (see Financial statements – Note 29 for more information).

We believe that the group has sufficient working capital for foreseeable requirements, taking into account the amounts of undrawn borrowing facilities and levels of cash and cash equivalents, and its ongoing ability to generate cash.

bp utilizes various arrangements in order to manage its working capital including discounting of receivables and, in the supply and trading business, the active management of supplier payment terms, inventory and collateral.

Standard & Poor's Ratings' long-term credit rating for BP p.l.c. is A- (negative outlook), the Moody's Investors Service rating is A1 (negative outlook) and the Fitch Ratings' long-term credit rating is A (stable).

The group's sources of funding, its access to capital markets and maintaining a strong cash position are described in Financial statements – Note 25 and Note 29. Further information on the management of liquidity risk and credit risk, and the maturity profile and fixed/floating rate characteristics of the group's debt are also provided in Financial statements– Note 26 and Note 29.

The information above contains forward-looking statements, which by their nature involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of bp. You are urged to read the Cautionary statement on page 329 and Risk factors on page 67, which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Off-balance sheet arrangements

At 31 December 2020, the group's share of third-party finance debt of equity-accounted entities was $19.9 billion (2019 $17.3 billion). These amounts are not reflected in the group's debt on the balance sheet. The group has issued third-party guarantees under which amounts outstanding, incremental to amounts recognized on the balance sheet, at 31 December 2020 were $1,405 million (2019 $692 million) in respect of liabilities of joint ventures★ and associates★ and $661 million (2019 $523 million) in respect of liabilities of other third parties. Of these amounts, $1,393 million (2019 $681 million) of the joint ventures and associates guarantees relate to borrowings and for other third-party guarantees, $568 million (2019 $494 million) relate to guarantees of borrowings.

Contractual obligations

The following table summarizes the group's capital expenditure commitments for property, plant and equipment at 31 December 2020 and the proportion of that expenditure for which contracts have been placed.

							$ million
							Payments due by period
Capital expenditure	Total	2021	2022	2023	2024	2025	2026 and thereafter
Committed	18,025	9,016	5,467	1,747	747	505	543
of which is contracted	8,009	4,878	2,805	166	65	27	68

Capital expenditure is considered to be committed when the project has received the appropriate level of internal management approval. For joint operations★, the net bp share is included in the amounts above.

In addition, at 31 December 2020, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $3,774 million. Contracts were in place for $1,270 million of this total.

The following table summarizes the group's principal contractual obligations at 31 December 2020, distinguishing between those for which a liability is recognized on the balance sheet and those for which no liability is recognized. Further information on borrowings is given in Financial statements – Note 26 and more information on leases is given in Financial statements – Note 28.

							$ million
							Payments due by period
Expected payments by period under contractual obligations	Total	2021	2022	2023	2024	2025	2026 and thereafter
Balance sheet obligations							
Borrowings[a]	81,076	13,981	7,541	8,146	9,001	7,445	34,962
Lease liabilities[b]	10,884	2,262	1,672	1,340	1,025	878	3,707
Decommissioning liabilities[c]	22,466	470	244	279	233	221	21,019
Environmental liabilities[c]	1,880	272	290	242	196	157	723
Gulf of Mexico oil spill liabilities[d]	14,569	1,409	1,278	1,222	1,141	1,136	8,383
Pensions and other post-retirement benefits[e]	17,448	1,039	978	946	922	917	12,646
	148,323	19,433	12,003	12,175	12,518	10,754	81,440
Off-balance sheet obligations							
Unconditional purchase obligations[f]							
Crude oil and oil products	44,322	35,702	4,495	1,988	993	477	667
Natural gas and LNG	35,337	11,255	4,779	3,155	2,442	1,465	12,241
Chemicals and other refinery feedstocks	684	422	70	63	54	53	22
Power	4,240	2,124	730	364	176	193	653
Utilities	762	91	91	53	51	50	426
Transportation	19,270	1,792	1,529	1,459	1,357	1,189	11,944
Use of facilities and services	19,830	2,810	2,010	1,628	1,358	1,207	10,817
	124,445	54,196	13,704	8,710	6,431	4,634	36,770
Total	272,768	73,629	25,707	20,885	18,949	15,388	118,210

[a] Expected payments include interest totalling $8,412 million ($1,503 million in 2021, $1,249 million in 2022, $1,115 million in 2023, $954 million in 2024, $793 million in 2025 and $2,798 million thereafter).

[b] Expected payments include interest totalling $1,622 million ($275 million in 2021, $228 million in 2022, $190 million in 2023, $156 million in 2024, $126 million in 2025 and $647 million thereafter).

[c] The amounts presented are undiscounted.

[d] The amounts presented are undiscounted. Gulf of Mexico oil spill liabilities are included in the group balance sheet, on a discounted basis, within other payables. See Financial statements – Note 22 for further information.

[e] Represents the expected future contributions to funded pension plans and payments by the group for unfunded pension plans and the expected future payments for other post-retirement benefits.

[f] Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms (such as fixed or minimum purchase volumes, timing of purchase and pricing provisions). Agreements that do not specify all significant terms, or that are not enforceable, are excluded. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2021 include purchase commitments existing at 31 December 2020 entered into principally to meet the group's short-term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Financial statements – Note 29.

Commitments for the delivery of oil and gas

We sell crude oil, natural gas and liquefied natural gas under a variety of contractual obligations. Some of these contracts specify the delivery of fixed and determinable quantities. For the period from 2021 to 2023 worldwide, we are contractually committed to deliver approximately 228 million barrels of oil, 8,500 billion cubic feet of natural gas, and 37 million tonnes of liquefied natural gas. The commitments principally relate to group subsidiaries★ based in Canada, Egypt, Singapore, United Kingdom and United States. We expect to fulfil these delivery commitments with production from our proved developed reserves and supplies from existing contracts, supplemented by market purchases as necessary.

Oil and gas disclosures for the group

Analysis by region

Our oil and gas operations are set out below by geographical area, with associated significant events for 2020. bp's percentage working interest in oil and gas assets is shown in brackets. Working interest is the cost-bearing ownership share of an oil or gas lease. Consequently, the percentages disclosed for certain agreements do not necessarily reflect the percentage interests in proved reserves, production or revenue. See page 320 for more information on Rosneft.

In addition to exploration, development and production activities, our Upstream business also includes certain midstream and liquefied natural gas (LNG) supply activities. Midstream activities involve the ownership and management of crude oil and natural gas pipelines, processing facilities and export terminals, LNG processing facilities and transportation, and our natural gas liquids (NGLs) processing business.

Our LNG activities are located in Abu Dhabi, Angola, Australia, Indonesia and Trinidad. In 2020 we marketed around 5.0 million tonnes of LNG production from these assets to IST which supplements equity production with merchant third party volumes to build a global trading portfolio. The LNG is marketed through contractual rights to access import terminal capacity in the liquid markets of Europe, UK and US, and relationships to market directly to end user customers or trading entities. LNG is supplied to all major LNG demand centres for example Argentina, Brazil, Caribbean, China, Croatia, Mediterranean and North West Europe, India, Israel, Japan, Singapore, South Korea, Taiwan, Thailand, Turkey and the UK.

Europe

bp is active in the North Sea and the Norwegian Sea. In 2020 bp's production came from three key areas: the Shetland area comprising the Clair, Foinaven, and Schiehallion fields; the central area comprising the Andrew area, Culzean, ETAP and Shearwater fields; and Norway, through our equity accounted 30% interest in Aker BP.

- On 29 March, bp confirmed completion of the restructuring of contractual arrangements for the Petrojari Foinaven floating production, storage and offloading vessel on the Foinaven field to the west of the Shetlands (bp 72% and operator).
- During the year, impairment charges of $2,796 million were recognized in respect of certain North Sea assets, primarily as a result of changes to the group's long-term price assumptions.
- In March 2020, EnQuest, the Thistle field operator, announced it no longer expected to re-start production at the Thistle field (bp 82%) . A Cessation of Production application was approved by the regulator in July, with an effective decommissioning date of 31 May 2020.
- During the third quarter, bp was awarded eight operated and three non-operated blocks in the North Sea as part of the UK Oil & Gas Authority 32nd offshore licensing round.
- On 6 October, bp confirmed that the planned divestment to Premier Oil of its interests in the Andrew area and Shearwater assets, both located in the UK North Sea, would not proceed following the announcement of a proposed merger between Chrysaor and Premier Oil. bp had announced this divestment in January 2020. The divestment was to cover the Andrew, Arundel, Cyrus, Farragon and Kinnoull fields plus bp's interest in Shearwater. Marketing of both assets continues.
- On 26 November, bp announced that production had started at the Vorlich field (bp 66%), just two years after the project was sanctioned. Vorlich is the latest in a programme of fast-paced, high-return subsea tiebacks in the UK North Sea. bp and partner Ithaca Energy invested £230 million to develop the field, which was discovered in 2014 and received regulatory approval for development in 2018.

North America

Our upstream activities in North America are located in four areas: deepwater Gulf of Mexico, the Lower 48 states, Canada and Mexico. Our interests in Alaska were disposed of during the year, further details are provided below.

bp has around 260 lease blocks in the Gulf of Mexico and operates four production hubs.

- On 25 August, bp confirmed it started production at Atlantis Phase 3 in the US Gulf of Mexico (bp 56% and operator).
- Construction and installation at the Thunder Horse South Expansion Phase 2 project is underway and drilling set to commence in the first half of 2021. First oil from the project is expected in the third quarter of 2021.
- bp was awarded 12 leases in the lease sale conducted in March and 10 leases in the sale held in November.
- The Mad Dog 2 project execute timeline was impacted by both COVID-19 and delays to fabrication of the floating production unit. The unit has now set sail from Korea, and wells activity and subsea installation are once again progressing. First oil is now expected in the second quarter of 2022.
- During the year, exploration write-offs of $2,643 million were recognized in relation to certain Gulf of Mexico assets, primarily due to management's re-assessment of expectations to extract value from certain exploration prospects as a result of a review of the group's long-term strategic plan and changes in the group's long-term price assumptions.

See also Financial Statements – Note 1 for further information on exploration leases.

bpx energy, bp's onshore oil and gas business in the Lower 48 states, has significant operated and non-operated activities across Louisiana, Texas and Wyoming producing natural gas, oil, NGLs and condensate, with primary focus on developing unconventional resources in Texas. It had a 1.5 billion boe proved reserve base at 31 December 2020, predominantly in unconventional reservoirs (tight gas★, shale gas and newly acquired shale oil). BPX Energy's assets span 2.1 million net developed acres and it had over 7,000 operated gross wells at 31 December 2020, with daily net production around 370mboe/d.

bpx energy operated as a separate business in 2020 while remaining part of the Upstream segment. With its own governance, systems and processes, it is structured to increase competitive performance through swift decision making and innovation, while maintaining bp's commitment to safe, reliable and compliant operations.

- During the year, impairment charges of $1,444 million were recognized in respect of certain bpx energy assets, primarily as a result of changes to the group's long term price assumptions.
- In December bp announced that it had reached agreement to sell its interest in the Wamsutter asset in Wyoming to Williams Field Services LLC. The transaction completed in January 2021.

bp's onshore US crude oil and product pipelines and related transportation assets were included in the Downstream segment in 2020.

In Alaska, BP Exploration (Alaska) Inc. (BPXA) operated nine North Slope oilfields in the Greater Prudhoe Bay area and held interests in three producing fields operated by others, as well as a non-operating interest in the Liberty development project prior to the completion in the second quarter of 2020 of the divestment of its Upstream business to Hilcorp Energy announced in 2019.

BP Pipelines (Alaska) Inc. (BPPA) owned a 49% interest in the Trans-Alaska Pipeline System (TAPS) prior to completion in the fourth quarter of 2020 of the divestment of its Midstream interests to Hilcorp Energy announced in 2019. As part of this transaction impairments of $1,002 million were recognized in 2020. bp retained the decommissioning liability relating to its interest in TAPS which will be partially offset by a 30% reimbursement of costs incurred from Hilcorp.

In Canada bp is focused on pursuing offshore exploration opportunities and its Sunrise Oil Sands operations. We have offshore exploration licences in Nova Scotia, Newfoundland and Labrador and the Canadian Beaufort Sea. In addition to Sunrise Oil Sands we hold interests in two further oil sands lease areas through the Terre de Grace partnership and the Pike Oil Sands joint operation★. In-situ steam-assisted gravity drainage (SAGD) technology is utilized in our existing oil sands operations, which uses the injection of steam into the reservoir to warm the bitumen so that it can flow to the surface through producing wells.

- The order issued by the government of Canada in 2019 prohibiting any work or activity authorized under the Canada Oil and Gas Operations Act on frontier lands that are situated in Canadian Arctic offshore waters remains in effect until 31 December 2021.
- During the year, impairment charges of $865 million were recognized in respect of certain assets in Canada, primarily as a result of changes to the group's long-term price assumptions.
- Also during the year, exploration write-offs of $2,539 million were recognized in relation to certain assets in Canada following management's re-assessment of expectations to extract value from certain exploration prospects as a result of a review of the group's long-term strategic plan and changes in the group's long-term price assumptions. A $247-million write-off was also recognized in relation to a prepayment for the Pike access pipeline.
- On 29 October, bp confirmed oil discoveries at the Cappahayden and Cambriol prospects in the Flemish Pass basin (bp 40%), offshore Newfoundland.

In Mexico, we have interests in two exploration joint operations in the Salina Basin with Equinor and Total, Block 1 (bp 33% and operator) and Block 3 (bp 33%), and in one exploration joint operation in the Sureste Basin with Total and Hokchi, a subsidiary of Pan American Energy Group (PAEG), Block 34 (bp 42.5% and operator).

South America

bp has upstream activities in Argentina, Brazil and Trinidad & Tobago and through PAEG, in Argentina, Bolivia and Uruguay.

In Argentina bp and Total are partners on a 50/50 basis in two offshore exploration concessions. Total is the operator.

In Brazil bp has interests in 22 exploration concessions across five basins.

- During the year, exploration write-offs of $2,141 million were recognized in relation to certain assets in Brazil following management's re-assessment of expectations to extract value from certain exploration prospects as a result of a review of the group's long-term strategic plan and changes in the group's long-term price assumptions.
- In the Foz do Amazonas basin, Total's request for a license extension for blocks FZA-M-57, 86, 88, 125 and 127was approved by the Brazilian regulatory authorities. Following their resignation from operatorship in August, Total reached agreement in October to transfer its working interest in these blocks to Petrobras. This transfer was also approved by the regulatory authorities.
- In FZA-M-59 block, bp requested a two year license extension to May 2022 which was approved by the ANP in June, based on Resolution 708/2017. bp also transferred its operatorship of this block to Petrobras, and this was approved by the ANP in October.
- bp reached an agreement to sell Itaipu and Wahoo exploration assets to PetroRio for $100 million to be paid in instalments from 2021 onwards; a further $40 million payment is contingent on pre-agreed conditions. The completion of this transaction is subject to the approval from the Brazilian regulatory authorities.

PAEG, a joint venture that is owned by bp (50%) and Bridas Corporation (50%), has activities mainly in Argentina and Mexico, but is also present in Uruguay and Bolivia.

- On 24 May, the Hokchi project in Mexico, operated by PAEG, achieved first oil, producing 1.2mboe/d in 2020.

In Trinidad & Tobago bp holds interests in exploration and production licences and production-sharing contracts★ (PSCs) covering 1.6 million acres offshore of the east and north-east coast. Facilities include 15 offshore platforms and two onshore processing facilities. Production comprises gas and associated liquids.

bp also holds interests in the Atlantic LNG facility. bp’s shareholding averages 39% across four LNG trains★ with a combined capacity of approximately 15 million tonnes per annum. During 2020 we sold gas to trains 1, 2 and 3 and processed gas in train 4. Most of the LNG produced from bp gas supplied to trains 2, 3 and 4 is sold to third parties under long- term contracts.

- The Cassia Compression project, a new compression platform with a 1.2bcf/d capacity bridge-linked to the Cassia B processing platform was expected to start up in 2021 but is delayed to 2022 as a result of COVID-19 impacting delivery lines.
- Impairment charges of $2,416 million were recognized in 2020 in respect of certain assets in Trinidad, primarily as a result of changes to the group's long-term price assumptions.
- bp holds a 30% interest in two deepwater blocks, Block 23(a) and TTDAA14, with BHP as the Operator holding a 70% interest. There were four successful exploration wells drilled in 2019 and appraisal work is ongoing on these discoveries.
- bp’s initial gas sales and LNG offtake arrangements for Atlantic LNG Train 1 ended in September 2018. Subsequently, short term gas sales and LNG offtake arrangements were established and rolled over up until December 2020, with bp lifting the majority of the LNG produced. The National Gas Company of Trinidad & Tobago (NGC) has agreed to fund the operating cost of Train 1 up to the end of December 2021 for the right but not the obligation to supply gas into Train 1 and offtake 100% of the resultant LNG.
- On 28 September, BP Trinidad and Tobago LLC started up the Galeota expansion project in Trinidad. The project comprises a new produced water handling facility, a new flare system, relocation of the control room away from production and upgrades to the existing condensate stabilization facility.
- bp is operator of the Manakin Block which was discovered in 1998 and is a cross border reservoir field with the Venezuelan reservoir, Cocuina. Manakin declared commerciality in January 2018 however cross border discussions have not progressed due to the US sanctions.

Africa

bp’s upstream activities in Africa are located in Algeria, Angola, Côte d'Ivoire, Egypt, The Gambia, Libya, Mauritania, São Tomé & Príncipe and Senegal. bp's interest in Madagascar was relinquished in 2020.

In Algeria bp, Sonatrach and Equinor are partners in the In Salah (bp 33.15%) and In Amenas (bp 45.89%) non-operated joint ventures that supply gas to the domestic and European markets.

In Angola, bp owns an interest in five major deepwater offshore licences and is operator in two of these, Blocks 18 and 31, that are producing. We also have an equity interest in the Angola LNG plant (bp 13.6%).

- During the year, exploration write-offs of $832 million were recognized in relation to certain assets in Angola following management's re-assessment of expectations to extract value from certain exploration prospects as a result of a review of the group's long-term strategic plan and changes in the group's long-term price assumptions.
- Also during the year, impairment charges of $316 million were recognized in relation to certain assets in Angola, primarily as a result of changes to the group's long-term price assumptions.
- Development progressed at the Total-operated Zinia 2 deep offshore development project in Block 17 (bp 15.84%) and first production is expected in 2021.
- During the year, construction activity started at the Platina project in Block 18, with first production expected in 2022.
- Following the signing of an agreement in December 2019 by bp and its partners with the Agência Nacional de Petróleo, Gás e Biocombustíveis (ANPG), to extend the production-sharing agreement★ (PSA) for Block 17 until 2045, all conditions precedent relating to the agreement were met in the second quarter of 2020 and the new agreement became effective on 1 April 2020. Under the agreement the state-owned company Sonangol acquired a 5% equity interest in the block on the effective date with a further 5% to be transferred in 2036.
- In June 2019, bp and the contractor group signed an agreement with ANPG, extending the PSA for Block 15 until 2032. Under the agreement Sonangol acquired a 10% equity interest in the block, reducing bp’s interest from 26.67% to 24%. All conditions precedent relating to the agreement were met on 27 January 2020 and the new agreement became effective as from 1 October 2019.

- In December 2018, bp and the contractor group signed an agreement with ANPG, extending the Block 18 PSA until 2032. Under the agreement, effective from 1 July 2020, Sonangol acquired an 8% equity interest in the block, reducing bp's interest from 50% to 46%. All conditions precedent relating to the agreement were met on 17 December 2020.

In Côte d'Ivoire, bp has interests in five offshore oil blocks with Kosmos Energy (KE) under agreements with the government of Côte d'Ivoire and the state oil company Société Nationale d'Operations Pétrolières de la Côte d'Ivoire (PETROCI) (bp 45%).

In Egypt, bp and its partners currently produce 60% of Egypt's gas production.

- During the year, exploration write-offs of $952 million were recognized in relation to certain assets in Egypt following management's re-assessment of expectations to extract value from certain exploration prospects as a result of a review of the group's long-term strategic plan and changes in the group's long-term price assumptions.
- In July, bp confirmed the Bashrush gas discovery, located offshore Egypt in the North El Hammad concession (bp 37.5%).
- On 16 September, bp confirmed a gas discovery with the Nidoco NW-1 exploratory well in the Abu Madi West development lease, offshore Egypt (bp 25%).
- On 26 October bp announced the start-up of gas production from the Qattameya gas field in the North Damietta offshore concession (bp 100%). Qattameya, whose discovery was announced in 2017, is located approximately 45 km west of the Ha'py platform and is tied back to the Ha'py and Tuart field development via a new 50km pipeline.
- Work on the West Nile Delta Raven project (BP 82.75%) is almost complete, with start up expected in the first quarter of 2021. Raven is the third project in North Alexandria and West Mediterranean deepwater offshore blocks.

In the Gambia, bp has a 90% interest in offshore block A1 with the state oil company, Gambia National Petroleum Corporation.

In Libya, bp partners with the Libyan Investment Authority (LIA) in an exploration and production sharing agreement (EPSA) to explore acreage in the onshore Ghadames and offshore Sirt basins (bp 85%). bp wrote off all balances associated with the Libya EPSA in 2015.

- bp, LIA and Eni continue to work with the NOC towards Eni acquiring a 42.5% interest in the bp-operated EPSA in Libya. On completion, Eni would become operator of the EPSA. The companies are continuing to work together to finalize and complete all agreements.

In Mauritania and Senegal, bp has a 62% participating interest in the C8, C12 and C13 exploration blocks in Mauritania and a 60% participating interest in the Cayar Profond Offshore and St Louis Profond Offshore exploration blocks in Senegal. We relinquished our interest in the C6 exploration block in October. Together the remaining blocks cover approximately 19,700 square kilometres. For the Greater Tortue Ahmeyin (GTA) Unit across the border of Mauritania and Senegal, bp has a 56% participating interest.

The Phase 1 construction activity for the GTA major project★ was severely affected by COVID-19 and the 2020 weather window for installation works was not met resulting in a delay to start up of around one year. A force majeure (FM) notice was issued under the lease and operate agreement with Golar LNG over the provision of a floating liquified natural gas vessel, where due to the FM event the lessee was not able to meet the connection date. On 1 October, bp confirmed force majeure was lifted on the project.

- During the first quarter, bp executed a gas sale and purchase agreement with partners in the Greater Tortue Ahmeyim (GTA) project.
- During the year, impairment charges and an exploration write-off totalling $2,260 million were recognized in respect of certain assets in the region, primarily as a result of changes to the group's long-term price assumptions.

In Madagascar, during the second quarter, following management's re-assessment of expectations to extract value from certain exploration prospects as a result of a review of the group's long-term strategic plan and changes in the group's long-term price assumptions, bp relinquished its interest in three PSCs (the fourth was relinquished in February 2020) for exploration licences situated offshore northwest Madagascar, under agreements with the government of Madagascar represented by Office des Mines Nationales et des Industries Stratégiques (OMNIS) (bp 100%).

In São Tomé & Príncipe, bp is operator in two offshore blocks under PSAs with Shell who acquired the interests of KE in December 2020, and the state oil company Agencia Nacional do Petroleo (bp 50%).

Asia

bp has activities in Abu Dhabi, Azerbaijan, China, India, Indonesia, Iraq, Kuwait, Oman and Russia.

In China we have a 30% equity stake in the Guangdong LNG regasification terminal and trunkline project with a total storage capacity of 640,000 cubic metres. The project is supplied under a long-term contract with Australia's North West Shelf venture (bp 16.67%).

In Azerbaijan, bp operates two PSAs, Azeri-Chirag-Gunashli (ACG) (bp 30.37%) and Shah Deniz (bp 28.83%) and also holds a number of other exploration leases.

- Naftiran Intertrade Co Ltd (NICO), a subsidiary of the National Iranian Oil Company, holds a 10% interest in the Shah Deniz joint venture. For information on the exclusion of this project from EU and US trade sanctions, or exemptions from such trade sanctions in relation to this project, see International trade sanctions on page 325.
- During the year, impairment charges of $537 million were recognized in respect of certain assets in the region, primarily as a result of changes to the group's long-term price assumptions.
- In January 2020 bp announced that drilling of the first well on the Shafag-Asiman offshore block had commenced. The drilling of the SAX01 well continued in 2020 and we expect it to reach the target depth in the first half of 2021.

bp holds a 30.1% interest in and operates the Baku-Tbilisi-Ceyhan oil pipeline. The 1,768-kilometre pipeline transports oil from the bp-operated ACG oilfield and gas condensate from the Shah Deniz gas field in the Caspian Sea, along with other third-party oil, to the eastern Mediterranean port of Ceyhan. The pipeline has a capacity of 1mmboe/d, with an average throughput in 2020 of 570mboe/d.

bp (as operator of Azerbaijan International Operating Company) also operates the Western Route Export Pipeline that transports ACG oil to Supsa on the Black Sea coast of Georgia, with an average throughput of 85mboe/d in 2020.

bp holds a 28.83% interest in and performs some operations for the 693 kilometre South Caucasus Pipeline. The pipeline takes gas from Azerbaijan through Georgia to the Turkish border and has a capacity of 440mboe/d (including expansion), with average throughput in 2020 of 210mboe/d.

bp also holds a 12% interest in the Trans Anatolian Natural Gas Pipeline (TANAP). In the first phase, which commenced in 2018, gas from Shah Deniz is transported to Eskisehir in Turkey. The capacity of the pipeline during the first phase is 100mboe/d and the average throughput in 2020 was 80mboe/d. The second phase takes gas further to TANAP's connection with the Trans Adriatic Pipeline (TAP) at the Turkey-Greece border. bp has a 20% interest in TAP, that takes gas through Greece and Albania into Italy. Commercial deliveries of gas via TAP commenced at the end of 2020.

In Oman bp operates Block 61, the largest tight gas★ development in the Middle East (bp 60%), and is a 50% owner in Block 77.

- The Block 77 Exploration and PSA was approved by Royal Decree in the first quarter of 2020, with a plan to process seismic and drill one exploration well within the next three years. ENI (50%) is operator during the exploration phase and bp will be the operator of any potential development.
- On 12 October, bp announced production had begun from the Block 61 Phase 2 Ghazeer gas field, around 33 months after bp and its partners approved the development. bp brought the project online ahead of the original planned start-up in early 2021, and under budget.
- On 1 February 2021 bp announced that it had agreed to sell a 20% participating interest in Block 61 to PTT Exploration and Production

★ See Glossary

Public Company Limited (PTTEP) of Thailand for a total consideration of $2.6 billion. Following completion of the sale, which is subject to Royal Decree, bp will remain operator of the block with a 40% interest.

In Abu Dhabi, bp holds a 10% interest in the ADNOC Onshore concession. We also have a 10% equity shareholding in ADNOC LNG and a 10% shareholding in the shipping company NGSCO. ADNOC LNG supplied approximately 5.69 million tonnes of LNG (0.748bcfe/d regasified) in 2020. Our interest in the ADNOC Onshore concession expires at the end of 2054.

In 2016 bp signed an enhanced technical service agreement for south and east Kuwait conventional oilfields, which includes the Burgan field, with Kuwait Oil Company. Delivery of the 2019-2020 plan was above target performance and implementation of the 2020-21 plan is underway.

In India we have a participating interest in two oil and gas PSAs (KG D6 33.33% and NEC25 33.33%), and one oil and gas block under a Revenue Sharing Contract (KG-UDWHP-2018/1 40%), all operated by Reliance Industries Limited (RIL). We also have a 50% stake in India Gas Solutions Private Limited, a joint venture with RIL, for the sourcing and marketing of gas in India.

- On 3 February, bp and RIL confirmed that they had completed the safe cessation of production in a planned manner, from the D1 D3 field in Block KG D6, off the east coast of India (bp 33.33%).
- During the year, impairment charges of $1,313 million were recognized in respect of certain assets in India, primarily as a result of changes to the group's long-term price assumptions.
- Also during the year, exploration write-offs of $333 million were recognized in relation to certain assets in India following management's re-assessment of expectations to extract value from certain exploration prospects as a result of a review of the group's long-term strategic plan and changes in the group's long-term price assumptions.
- On 18 December, bp and RIL announced the start of gas production from R-Series, the first of the three projects in Block KG D6. The other two projects (Satellites Cluster and MJ) are under development with first gas production phased over 2021-2022.

In Indonesia bp successfully completed the purchase of a 30% non-operated working interest in the Andaman II PSC from KrisEnergy in April. Andaman II is a deep-water block covering 7,400 square kilometres area in the North Sumatra basin, offshore from Aceh. Other interest holders are Premier Oil (40%, operator) and Mubadala Petroleum (30%).

In Iraq bp holds a 47.6% working interest and is the lead contractor in the Rumaila technical service contract in southern Iraq. The technical services contract runs to December 2034. Rumaila is one of the world's largest oil fields, comprising five producing reservoirs. bp's activities have not been materially impacted by the continued political instability and public protests which have occurred in 2020.

In Russia in addition to its interest in Rosneft as detailed on page 320, bp holds a 20% interest in Taas-Yuryakh Neftegazodobycha (Taas) together with Rosneft (50.1%) and a consortium comprising Oil India Limited, Indian Oil Corporation Limited and Bharat PetroResources Limited (29.9%). Taas is developing the Srednebotuobinskoye oil and gas condensate field in East Siberia. Also with Rosneft, we hold a 49% interest in Kharampurneftegaz LLC (Kharampur) to develop subsoil resources within the Kharampurskoe and Festivalnoye licence areas in Yamalo-Nenets. Rosneft (51%) and bp (49%) jointly own Yermak Neftegaz LLC (Yermak), which conducts onshore exploration in the West Siberian and Yenisei-Khatanga basins and currently holds six exploration and production licences.

- During the year bp received $86 million of dividends net of withholding taxes and $51 million of distribution of paid in capital from Taas.

Australasia

bp has activities in Australia and Eastern Indonesia.

In Australia bp is one of seven participants in the North West Shelf (NWS) venture, which has been producing LNG, pipeline gas, condensate, LPG and oil since the 1980s. Six partners (including bp) hold an equal 16.67% interest in the gas infrastructure and an equal 15.78% interest in the gas and condensate reserves, with a seventh partner owning the remaining 5.32%. bp also has a 16.67% interest in some of the NWS oil reserves and related infrastructure. The NWS venture is currently the largest single source supplier to the domestic market in Western Australia and one of the largest LNG export projects in the region, with five LNG trains in operation. bp's net share of the capacity of NWS LNG trains 1-5 is 2.7 million tonnes of LNG per year.

bp is also one of five participants in the Browse LNG venture (operated by Woodside) and holds a 17.33% interest.

- The Browse joint venture participants continue to progress the development of Browse by connecting it via a 900km pipeline to the NWS Venture's Karratha Gas Plant.

In Papua Barat, Eastern Indonesia, bp operates the Tangguh LNG plant (bp 40.22%). The asset currently comprises 16 producing wells, two offshore platforms, two pipelines and an LNG plant with two production trains. It has a total capacity of 7.6 million tonnes of LNG per annum. Tangguh supplies LNG to customers in Indonesia, Mexico, China, South Korea, and Japan through a combination of long, medium and short-term contracts.

The Tangguh expansion project comprises a third LNG processing train, two offshore platforms, 10 new production wells, an expanded LNG loading facility, and supporting infrastructure. The project will add 3.8 million tonnes per annum (mtpa) of production capacity to the existing facility, bringing total plant capacity to 11.4mtpa. Due to COVID-19 and the need to relocate personnel from the remote project, the start-up is expected to be delayed to 2022.

Oil and natural gas

Resource progression

bp manages its hydrocarbon resources in three major categories: prospect inventory, contingent resources and reserves. When a discovery is made, volumes usually transfer from the prospect inventory to the contingent resources category. The contingent resources move through various sub-categories as their technical and commercial maturity increases through appraisal activity.

At the point of final investment decision, most proved reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. When part of a well's proved reserves depends on a later phase of activity, only that portion of proved reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will typically occur at the point of first oil or gas production. Major development projects typically take one to five years from the time of initial booking of PUD to the start of production. Changes to proved reserves bookings may be made due to analysis of new or existing data concerning production, reservoir performance, commercial factors and additional reservoir development activity.

Volumes can also be added or removed from our portfolio through acquisition or divestment of properties and projects. When we dispose of an interest in a property or project, the volumes associated with our adopted plan of development for which we have a final investment decision will be removed from our proved reserves upon completion of the transaction. When we acquire an interest in a property or project, the volumes associated with the existing development and any committed projects will be added to our proved reserves if bp has made a final investment decision and they satisfy the SEC's criteria for attribution of proved status. Following the acquisition, additional volumes may be progressed to proved reserves from non-proved reserves or contingent resources.

Non-proved reserves and contingent resources in a field will only be recategorized as proved reserves when all the criteria for attribution of proved status have been met and the volumes are included in the business plan and scheduled for development, typically within five years. bp will only book proved reserves where development is scheduled to commence after more than five years, if these proved reserves satisfy the SEC's criteria for attribution of proved status and bp management has reasonable certainty that these proved reserves will be produced.

At the end of 2020 bp had material volumes of proved undeveloped reserves held for more than five years in Russia, Trinidad, Gulf of Mexico, Azerbaijan, Indonesia and the North Sea. These are part of ongoing infrastructure-led development activities for which bp has a historical track record of completing comparable projects in these countries. We have no proved undeveloped reserves held for more than five years in our onshore US developments.

In each case the volumes are being progressed as part of an adopted development plan where there are physical limits to the development timing such as infrastructure limitations, contractual limits including gas delivery commitments, late life compression and the complex nature of working in remote locations, or where there are significant commitments on delivery to the relevant authority.

Over the past five years, bp has annually progressed a weighted average 17% (19% for 2019 five-year average) of our group proved undeveloped reserves (including the impact of disposals and price acceleration effects in PSAs) to proved developed reserves. This equates to a turnover time of six years.

Proved reserves as estimated at the end of 2020 meet bp's criteria for project sanctioning and SEC tests for proved reserves. We have not halted or changed our commitment to proceed with any material project to which proved undeveloped reserves have been attributed.

In 2020 we progressed 897 mmboe of proved undeveloped reserves (512 mmboe for our subsidiaries★ alone) to proved developed reserves through ongoing investment in our subsidiaries' and equity-accounted entities' upstream development activities. Total development expenditure, excluding midstream activities, was $11,041 million in 2020 ($7,650 million for subsidiaries and $3,391 million for equity-accounted entities). The major areas with progressed volumes in 2020 were Russia, US, Egypt and Oman. Revisions of previous estimates for proved undeveloped reserves are due to changes relating to field performance, well results or changes in commercial conditions including price impacts. The following tables describe the changes to our proved undeveloped reserves position through the year for our subsidiaries and equity-accounted entities and for our subsidiaries alone.

Subsidiaries and equity-accounted entities	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2020	**8,152**
Revisions of previous estimates	**298**
Improved recovery	**133**
Discoveries and extensions	**436**
Purchases	**442**
Sales	**(940)**
Total in year proved undeveloped reserves changes	**369**
Proved developed reserves reclassified as undeveloped	**247**
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	**(897)**
Proved undeveloped reserves at 31 December 2020	**7,871**

Subsidiaries only	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2020	**3,771**
Revisions of previous estimates	**42**
Improved recovery	**122**
Discoveries and extensions	**84**
Purchases	**—**
Sales	**(8)**
Total in year proved undeveloped reserves changes	**240**
Proved developed reserves reclassified as undeveloped	**173**
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	**(512)**
Proved undeveloped reserves at 31 December 2020	**3,673**

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

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. bp only applies technologies that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. bp applies high-resolution seismic data for the identification of reservoir extent and fluid contacts only where there is an overwhelming track record of success in its local application. In certain cases bp uses numerical simulation as part of a holistic assessment of recovery factor for its fields, where these simulations have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In certain deepwater fields bp has booked proved reserves before production flow tests are conducted, in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. To determine reasonable certainty of commercial recovery, bp employs a general method of reserves assessment that relies on the integration of three types of data:

- well data used to assess the local characteristics and conditions of reservoirs and fluids
- field scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control
- data from relevant analogous fields.

Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. bp considers the integration of this data in certain cases to be superior to a flow test in providing understanding of overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be

★ See Glossary

determined over a greater volume than the localized volume of investigation associated with a short-term flow test. There is a strong track record of proved reserves recorded using these methods, validated by actual production levels.

Governance

bp's centrally controlled process for proved reserves estimation approval forms part of a holistic and integrated system of internal control. It consists of the following elements:

- Accountabilities of certain officers of the group to ensure that there is review and approval of proved reserves bookings independent of the operating business and that there are effective controls in the approval process and verification that the proved reserves estimates and the related financial impacts are reported in a timely manner.
- Capital allocation processes, whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group's business plan. A formal review process exists to ensure that both technical and commercial criteria are met prior to the commitment of capital to projects.
- Group audit, whose role is to consider whether the group's system of internal control is adequately designed and operating effectively to respond appropriately to the risks that are significant to bp.
- Approval hierarchy, whereby proved reserves changes above certain threshold volumes require immediate review and all proved reserves require annual central authorization and have scheduled periodic reviews. The frequency of periodic review ensures that 100% of the bp proved reserves base undergoes central review every three years.

bp's vice president of segment reserves is the individual primarily responsible for overseeing the preparation of the reserves estimate. He has more than 27 years of diversified industry experience in reserves estimation with the past 2 years managing the governance and compliance. He is a past Chairman of the Society of Petroleum Engineers (Russia & Caspian) and a member of the United Nations Economic Commission for Europe Expert Group on Resource Management.

No specific portion of compensation bonuses for senior management is directly related to proved reserves targets. Additions to proved reserves is one of several indicators by which the performance of the Upstream segment is assessed by the remuneration committee for the purposes of determining compensation bonuses for the executive directors. Other indicators include a number of financial and operational measures.

bp's variable pay programme for the other senior managers in the Upstream segment is based on individual performance contracts. Individual performance contracts are based on agreed items from the business performance plan, one of which, if chosen, could relate to proved reserves.

Compliance

International Financial Reporting Standards (IFRS) do not provide specific guidance on reserves disclosures. bp estimates proved reserves in accordance with SEC Rule 4-10 (a) of Regulation S-X and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins as issued by the SEC staff.

By their nature, there is always risk involved in the ultimate development and production of proved reserves including, but not limited to: final regulatory approval; the installation of new or additional infrastructure, as well as changes in oil and gas prices; changes in operating and development costs; and the continued availability of additional development capital. All the group's proved reserves held in subsidiaries and equity-accounted entities are estimated by the group's petroleum engineers or by independent petroleum engineering consulting firms and then assured by the group's petroleum engineers.

DeGolyer & MacNaughton (D&M), an independent petroleum engineering consulting firm, has estimated the net proved crude oil, condensate, natural gas liquids (NGLs) and natural gas reserves, as of 31 December 2020, of certain properties owned by Rosneft as part of our equity-accounted proved reserves. The properties evaluated by D&M account for 100% of Rosneft's net proved reserves as of 31 December 2020. The net proved reserves estimates prepared by D&M were prepared in accordance with the reserves definitions of Rule 4-10(a)(1)-(32) of Regulation S-X. All reserves estimates involve some degree of uncertainty. bp has filed D&M's independent report on its reserves estimates as an exhibit to this Annual Report on Form 20-F filed with the SEC.

Netherland, Sewell & Associates (NSAI), an independent petroleum engineering consulting firm, has estimated the net proved crude oil, condensate, natural gas liquids (NGLs) and natural gas reserves, as of 31 December 2020, of certain properties owned by bp in the US Lower 48. The properties evaluated by NSAI account for 100% of bp's net proved reserves in the US Lower 48 as of 31 December 2020. The net proved reserves estimates prepared by NSAI were prepared in accordance with the reserves definitions of Rule 4-10(a)(1)-(32) of Regulation S-X. All reserves estimates involve some degree of uncertainty. bp has filed NSAI's independent report on its reserves estimates as an exhibit to this Annual Report on Form 20-F filed with the SEC.

Our proved reserves are associated with both concessions (tax and royalty arrangements) and agreements where the group is exposed to the upstream risks and rewards of ownership, but where our entitlement to the hydrocarbons is calculated using a more complex formula, such as with PSAs. In a concession, the consortium of which we are a part is entitled to the proved reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the proved reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves.

We disclose our share of proved reserves held in equity-accounted entities (joint ventures★ and associates★), although we do not control these entities or the assets held by such entities.

bp's estimated net proved reserves and proved reserves replacement

92% of our total proved reserves of subsidiaries at 31 December 2020 were held through joint operations★ (91% in 2019), and 31% of the proved reserves were held through such joint operations where we were not the operator (28% in 2019).

Estimated net proved reserves of crude oil at 31 December 2020[a b c]

			million barrels
	Developed	Undeveloped	Total
UK	**162**	**148**	**309**
US[d]	**697**	**742**	**1,438**
Rest of North America[d]	**37**	**195**	**232**
South America[e]	**8**	**9**	**16**
Africa	**116**	**21**	**137**
Rest of Asia	**1,100**	**547**	**1,647**
Australasia	**34**	**5**	**38**
Subsidiaries	**2,154**	**1,666**	**3,819**
Equity-accounted entities	**3,517**	**2,776**	**6,293**
Total	**5,671**	**4,441**	**10,112**

Estimated net proved reserves of natural gas liquids at 31 December 2020[a b]

			million barrels
	Developed	Undeveloped	Total
UK	**7**	**—**	**7**
US	**115**	**218**	**333**
Rest of North America	**—**	**—**	**—**
South America	**2**	**19**	**21**
Africa	**13**	**1**	**14**
Rest of Asia	**—**	**—**	**—**
Australasia	**2**	**—**	**2**
Subsidiaries	**139**	**237**	**376**
Equity-accounted entities	**129**	**44**	**172**
Total	**268**	**281**	**549**

★ See Glossary

Estimated net proved reserves of liquids★

			million barrels
	Developed	Undeveloped	Total
Subsidiaries[e]	2,293	1,903	4,196
Equity-accounted entities[f]	3,645	2,819	6,465
Total	**5,938**	**4,722**	**10,661**

Estimated net proved reserves of natural gas at 31 December 2020[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	306	51	358
US	1,921	3,423	5,344
Rest of North America	—	—	—
South America[g]	1,567	1,964	3,531
Africa	1,382	158	1,541
Rest of Asia	3,883	3,641	7,524
Australasia	2,058	1,029	3,087
Subsidiaries	11,118	10,267	21,385
Equity-accounted entities[h]	13,088	7,994	21,082
Total	**24,206**	**18,260**	**42,467**

Estimated net proved reserves on an oil equivalent basis[i]

			million barrels of oil equivalent
	Developed	Undeveloped	Total
Subsidiaries	4,210	3,673	7,883
Equity-accounted entities	5,902	4,198	10,100
Total	**10,112**	**7,871**	**17,982**

[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, and include non-controlling interests in consolidated operations. We disclose our share of reserves held in joint ventures and associates that are accounted for by the equity method although we do not control these entities or the assets held by such entities.

[b] The 2020 marker prices used were Brent★ $41.31/bbl (2019 $62.74/bbl and 2018 $71.43/bbl) and Henry Hub★ $1.94/mmBtu (2019 $2.58/mmBtu and 2018 $3.10/mmBtu).

[c] Includes condensate.

[d] All of the reserves in Canada are bitumen.

[e] Includes 11 million barrels of liquids in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[f] Includes 405 million barrels in respect of the non-controlling interest in Rosneft, including 19mmboe held through bp's interests in Russia other than Rosneft.

[g] Includes 1,059 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[h] Includes 1,640 billion cubic feet of natural gas in respect of the 10.01% non-controlling interest in Rosneft including 614 billion cubic feet held through bp's interests in Russia other than Rosneft.

[i] Includes 264 million barrels of oil equivalent associated with Assets Held for Sale in Oman.

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

Proved reserves replacement

Total hydrocarbon proved reserves at 31 December 2020, on an oil equivalent basis including equity-accounted entities, decreased by 7% compared with 31 December 2019. Natural gas represented about 41% (47% for subsidiaries and 36% for equity-accounted entities) of these reserves. The change includes a net decrease from acquisitions and disposals of 1,069mmboe (decrease of 1,072mmboe within our subsidiaries and increase of 3mmboe within our equity-accounted entities). Acquisition and divestment activity occurred in our equity-accounted entities in Russia, and divestment activity in our subsidiaries in the US including Alaska.

The proved reserves replacement ratio★ is the extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, and extensions and discoveries. For 2020, the proved reserves replacement ratio excluding acquisitions and disposals was 78% (67% in 2019 and 100% in 2018) for subsidiaries and equity-accounted entities, 47% for subsidiaries alone and 127% for equity-accounted entities alone. There was a net decrease (373mmboe) of reserves due to lower gas and oil prices within the US, North Sea and Angola partly offset by increases related to price in some of our PSAs in Iraq and Azerbaijan.

In 2020 net additions to the group's proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 1,006mmboe (380mmboe for subsidiaries and 626mmboe for equity-accounted entities), through revisions to previous estimates including price, improved recovery from, and extensions to, existing fields and discoveries of new fields. The subsidiary additions were through improved recovery from, and extensions to, existing fields and discoveries of new fields where they represented a mixture of proved developed and proved undeveloped reserves. Volumes added in 2020 principally resulted from the application of conventional technologies and extensions of field size by development drilling. The principal proved reserves additions in our subsidiaries by region were in the US, Oman, Azerbaijan and Angola. The principal reserves additions in our equity-accounted entities were in Rosneft and Pan American Energy Group.

16% of our proved reserves are associated with PSAs. The countries in which we produced under PSAs in 2020 were Algeria, Angola, Azerbaijan, Egypt, India, Indonesia and Oman. In addition, the technical service contract (TSC) governing our investment in the Rumaila field in Iraq functions as a PSA.

The group holds no licences due to expire within the next three years that would have a significant impact on bp's reserves or production. bp holds reserves classified as Assets held for sale in Oman.

For further information on our reserves see page 238.

bp's net production by country – crude oil[a] and natural gas liquids

						thousand barrels per day
						bp net share of production[b]
			Crude oil			Natural gas liquids
	2020	2019	2018	**2020**	2019	2018
Subsidiaries						
UK[c d]	**96**	100	101	**5**	3	5
Total Europe	**96**	100	101	**5**	3	5
Alaska[c]	**38**	71	106	**—**	—	—
Lower 48 onshore[c]	**72**	66	18	**59**	58	37
Gulf of Mexico deepwater[c]	**235**	263	261	**20**	24	23
Total US	**345**	400	385	**79**	81	60
Canada[e]	**22**	24	24	**—**	—	—
Total Rest of North America	**22**	24	24	**—**	—	—
Total North America	**367**	424	408	**79**	81	60
Trinidad & Tobago	**7**	7	7	**7**	9	9
Total South America	**7**	7	7	**7**	9	9
Angola	**108**	115	147	**—**	—	—
Egypt[c]	**9**	34	49	**—**	—	—
Algeria	**6**	7	9	**8**	8	11
Total Africa	**123**	156	204	**8**	8	11
Abu Dhabi	**158**	180	169	**—**	—	—
Azerbaijan	**97**	79	72	**—**	—	—
Iraq	**100**	64	54	**—**	—	—
Oman	**21**	20	17	**—**	—	—
Total Rest of Asia	**375**	343	313	**—**	—	—
Total Asia	**375**	343	313	**—**	—	—
Australia	**13**	15	16	**2**	2	2
Eastern Indonesia	**2**	2	2	**—**	—	—
Total Australasia	**15**	17	17	**2**	2	2
Total subsidiaries	**983**	1,046	1,051	**101**	104	88
Equity-accounted entities (bp share)						
Rosneft[f] (Russia, Venezuela)	**873**	920	919	**3**	3	4
Abu Dhabi	**—**	—	16	**—**	—	—
Argentina	**52**	54	52	**1**	1	—
Mexico	**0**	—	—	**—**	—	—
Bolivia	**2**	2	3	**—**	—	—
Egypt[c]	**—**	—	—	**2**	3	3
Norway	**50**	35	34	**3**	2	2
Russia[c]	**30**	35	14	**—**	—	—
Angola	**1**	1	1	**5**	5	3
Total equity-accounted entities	**1,009**	1,047	1,040	**14**	14	12
Total subsidiaries and equity-accounted entities[g]	**1,991**	2,093	2,091	**115**	118	100

[a] Includes condensate.

[b] 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.

[c] In 2020, bp disposed of its Alaska interests and certain Lower 48 onshore interests in the US. In 2019, bp completed the sale of its interest in the Gulf of Suez Petroleum Company (GUPCO) in Egypt and certain US assets in Lower 48 onshore and disposed of its interests in the Gulf of Mexico Santiago and Santa Cruz wells. In 2018, bp acquired various interests in the Permian Basin, Eagle Ford and Haynesville Shales in Lower 48 onshore as a result of the acquisition of BHP's US unconventional assets, increased its interest in the Clair asset in the UK North Sea, and acquired an interest in LLC Kharampurneftegaz in Russia, and in certain US offshore assets. It also disposed of its interests in the Greater Kuparuk Area in Alaska, the Magnus field in the UK North Sea, and in certain other assets in the UK North Sea and US onshore assets.

[d] Volumes relate to six bp-operated fields within ETAP. bp has no interests in the remaining three ETAP fields, which are operated by Shell.

[e] All of the production from Canada in Subsidiaries is bitumen.

[f] Includes production in respect of the non-controlling interest in Rosneft, including production held through bp's interests in Russia other than Rosneft.

[g] Includes 3 net mboe/d of NGLs from processing plants in which bp has an interest (2019 3mboe/d and 2018 3mboe/d).

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

bp's net production by country – natural gas

			million cubic feet per day
			bp net share of production[a]
	2020	2019	2018
Subsidiaries			
UK[b]	**221**	129	152
Total Europe	**221**	129	152
Lower 48 onshore[b]	**1,405**	2,175	1,705
Gulf of Mexico deepwater[b]	**154**	179	190
Alaska[b]	**3**	4	5
Total US	**1,561**	2,358	1,900
Canada	**2**	2	7
Total Rest of North America	**2**	2	7
Total North America	**1,563**	2,361	1,907
Trinidad & Tobago	**1,695**	1,977	2,136
Total South America	**1,695**	1,977	2,136
Egypt[b]	**782**	952	878
Algeria	**141**	186	183
Total Africa	**923**	1,138	1,061
Azerbaijan	**413**	367	256
India	**2**	15	32
Oman	**550**	594	538
Total Rest of Asia	**966**	976	826
Total Asia	**966**	976	826
Australia	**396**	411	437
Eastern Indonesia	**399**	375	382
Total Australasia	**795**	786	819
Total subsidiaries[c]	**6,163**	7,366	6,900
Equity-accounted entities (bp share)			
Rosneft[d] (Russia, Canada, Egypt, Vietnam)	**1,286**	1,279	1,286
Argentina	**230**	250	264
Bolivia	**56**	64	71
Mexico	**0**	—	—
Norway	**61**	56	59
Russia[b]	**41**	—	—
Angola	**92**	87	80
Total equity-accounted entities[c]	**1,765**	1,736	1,760
Total subsidiaries and equity-accounted entities	**7,929**	9,102	8,659

[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] In 2020, bp disposed of its Alaska interests and certain Lower 48 onshore interests in the US. In 2019, bp completed the sale of its interest in the Gulf of Suez Petroleum Company (GUPCO) in Egypt and certain US assets in Lower 48 onshore and disposed of its interests in the Gulf of Mexico Santiago and Santa Cruz wells. In 2018, bp acquired various interests in the Permian Basin, Eagle Ford and Haynesville Shales in Lower 48 onshore as a result of the acquisition of BHP's US unconventional assets, increased its interest in the Clair asset in the UK North Sea, and acquired an interest in LLC Kharampurneftegaz in Russia, and in certain US offshore assets. It also disposed of its interests in the Greater Kuparuk Area in Alaska, the Magnus field in the UK North Sea, and in certain other assets in the UK North Sea and US onshore assets.

[c] Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field, but the related reserves are included in the group's reserves.

[d] Includes production in respect of the non-controlling interest in Rosneft, including production held through bp's interests in Russia other than Rosneft.

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

The following tables provide additional data and disclosures in relation to our oil and gas operations.

Average sales price per unit of production (realizations★)[a]

$ per unit of production

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia[b]	Rest of Asia		
Subsidiaries										
2020										
Crude oil[c]	**42.70**	**—**	**38.14**	**26.70**	**42.27**	**41.60**	**—**	**37.76**	**33.21**	**38.46**
Natural gas liquids	**25.31**	**—**	**10.22**	**—**	**16.49**	**25.39**	**—**	**—**	**24.73**	**12.91**
Gas	**3.13**	**—**	**1.30**	**1.70**	**1.86**	**3.89**	**—**	**3.91**	**4.66**	**2.75**
2019										
Crude oil[c]	65.44	—	59.19	40.92	63.30	63.75	—	64.39	59.65	61.56
Natural gas liquids	29.58	—	14.67	—	25.86	31.89	—	—	38.11	18.23
Gas	4.01	—	1.93	0.75	2.78	4.59	—	3.99	6.86	3.39
2018										
Crude oil[c]	71.28	—	67.11	33.57	69.17	68.81	—	70.80	67.54	67.81
Natural gas liquids	31.63	—	25.81	—	35.74	39.14	—	—	52.14	29.42
Gas	7.71	—	2.43	0.83	3.08	4.82	—	3.85	7.97	3.92
Equity-accounted entities[d]										
2020										
Crude oil[c]	**—**	**40.00**	**—**	**—**	**40.41**	**—**	**35.10**	**—**	**—**	**35.94**
Natural gas liquids[e]	**—**	**—**	**—**	**—**	**15.93**	**—**	**N/A**	**—**	**—**	**15.93**
Gas	**—**	**3.76**	**—**	**—**	**2.88**	**—**	**1.51**	**—**	**—**	**1.85**
2019										
Crude oil[c]	—	64.75	—	—	56.85	—	56.52	—	—	56.96
Natural gas liquids[e]	—	—	—	—	18.14	—	N/A	—	—	18.14
Gas	—	5.01	—	—	3.98	—	1.83	—	—	2.38
2018										
Crude oil[c]	—	70.24	—	—	62.35	—	62.51	39.49	—	62.29
Natural gas liquids[e]	—	—	—	—	—	—	N/A	—	—	—
Gas	—	7.93	—	—	4.36	—	1.70	—	—	2.50

Average production cost per unit of production[f]

$ per unit of production

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia[c]	Rest of Asia		
Subsidiaries										
2020	**12.49**	**—**	**8.11**	**12.46**	**3.76**	**7.71**	**—**	**4.41**	**2.02**	**6.39**
2019	13.22	—	8.46	13.36	3.36	7.95	—	5.15	2.33	6.84
2018	13.76	—	9.63	13.10	3.08	7.31	—	5.72	2.35	7.15
Equity-accounted entities										
2020	**—**	**8.14**	**—**	**—**	**12.71**	**—**	**3.54**	**—**	**—**	**4.55**
2019	—	12.51	—	—	11.50	—	3.45	—	—	4.50
2018	—	12.15	—	—	10.61	—	3.37	5.92	—	4.38

[a] Units of production are barrels for liquids and thousands of cubic feet for gas. Realizations include transfers between businesses, except in the case of Russia.

[b] An amendment has been made to 2019 and 2018 to align with the disclosures for oil and natural gas exploration and production activities.

[c] Includes condensate.

[d] In certain countries it is common for equity-accounted entities' agreements to include pricing clauses that require selling a significant portion of the entitled production to local governments or markets at discounted prices.

[e] Natural gas liquids for Russia are included in crude oil.

[f] Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

Additional information for Downstream

Refinery throughputs[a b]

			thousand barrels per day
	2020	2019	2018
US	**693**	737	703
Europe	**742**	787	781
Rest of the world	**192**	225	241
Total	**1,627**	1,749	1,725
			%
Refining availability★	**96.0**	94.9	95.0

[a] This does not include bp's interest in Pan American Energy Group.

[b] Refinery throughputs reflect crude oil and other feedstock volumes.

Sales volume

			thousand barrels per day
	2020	2019	2018
Marketing sales[a]	**2,275**	2,727	2,736
Trading/supply sales[b]	**3,026**	3,268	3,194
Total refined product sales	**5,301**	5,995	5,930
Crude oil[c]	**2,397**	2,713	2,624
Total	**7,698**	8,708	8,554

[a] Marketing sales include branded and unbranded sales of refined fuel products and lubricants to business-to-business and business-to-consumer customers, including service station dealers, jobbers, airlines, small and large resellers such as hypermarkets, and the military.

[b] Trading/supply sales are fuel sales to large unbranded resellers and other oil companies.

[c] Crude oil sales relate to transactions executed by our integrated supply and trading function, primarily for optimizing crude oil supplies to our refineries and in other trading. 2020 includes 44 thousand barrels per day relating to revenues reported by the Upstream segment.

Sales volumes reported in the table above are for those transactions that are reported as gross sales in the group income statement. From 2021, certain sales and purchase transactions that have previously been reported gross in the group income statement will be reported on a net basis in the income statement. The volumes for 2020 transactions that would have been subject to potential netting in the income statement but are presented gross in this table are approximately 2,063 thousand barrels a day of crude oil, 2,613 thousand barrels a day of trading/supply sales, and 126 thousand barrels a day of marketing sales.

Retail sites[a]

			Number of bp-branded retail sites
	2020	2019	2018
US	**7,300**	7,200	7,200
Europe	**8,200**	8,200	8,200
Rest of the world	**4,800**	3,500	3,300
Total	**20,300**	18,900	18,700

[a] Reported to the nearest 100. Includes sites operated by dealers, jobbers, franchisees, brand licensees or JV partners, under the bp brand. These may move to and from the bp brand as their fuel supply agreement or brand licence agreement expires and are renegotiated in the normal course of business. Retail sites are primarily branded *bp*, *ARCO*, *Amoco*, *Aral* and *Thorntons*, and also include sites in India through our Jio-bp JV.

Reconciliation of RC profit before interest and tax to gross margin for convenience, retail fuels and electrification

		$ billion
	2020	2019
RC profit before interest and tax for Downstream	**3.4**	6.5
Net (favourable) adverse impact of non-operating items★ and fair value accounting effects★	**(0.3)**	(0.1)
Underlying RC profit before interest and tax for Downstream	**3.1**	6.4
Subtract underlying RC profit (loss) for petrochemicals, refining and trading, and lubricants	**1.0**	3.9
Add back:		
Fuels (excluding refining and trading) depreciation, depletion and amortization	**1.0**	1.0
Fuels (excluding refining and trading) production and manufacturing, distribution and administration expenses and adjusted for aviation, B2B and midstream gross margin	**1.9**	1.8
Adjusted for earnings from equity-accounted entities in fuels (excluding refining and trading)	**(0.2)**	(0.3)
Gross margin for convenience, retail fuels and electrification★	**4.8**	5.0
Of which:		
Convenience gross margin	**1.3**	1.2
Retail fuels gross margin	**3.5**	3.7
Electrification gross margin	**0.0**	0.0

★ See Glossary

Refinery capacity

The following table[a] summarizes bp group's interests in refineries and average daily crude distillation capacities as at 31 December 2020.

			Crude distillation capacities[b]	
Fuels value chain	Country	Refinery	Group interest[c] (%)	BP share thousand barrels per day
US				
US North West	US	Cherry Point	100	**251**
US East of Rockies		Whiting	100	**440**
		Toledo	50	**80**
				771
Europe				
Rhine	Germany	Gelsenkirchen	100	**265**
		Lingen	100	**97**
	Netherlands	Rotterdam	100	**390**
Iberia	Spain	Castellón	100	**110**
				862
Rest of world				
Australia	Australia	Kwinana[d]	100	**152**
New Zealand	New Zealand	Whangarei[ef]	10.1	**34**
Southern Africa	South Africa	Durban[e]	50	**90**
				276
Total bp share of capacity at 31 December 2020				**1,909**

[a] This does not include bp's interest in Pan American Energy Group.
[b] Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period under normal operational conditions.
[c] bp share of equity, which is not the same as bp share of processing entitlements.
[d] In the fourth quarter 2020, we announced plans to cease fuel production at our Kwinana Refinery and convert it to an import terminal.
[e] Indicates refineries not operated by bp.
[f] Reflects bp share of processing entitlement, which is not the same as bp share of equity.

Additional information for Rosneft

About Rosneft

Rosneft is the largest oil company in Russia, with a strong portfolio of current and future opportunities. Russia has one of the largest and lowest-cost hydrocarbon resource bases in the world and its resources play an important role in long-term energy supply to the global economy.

Rosneft is one of the largest publicly traded oil companies in the world based on hydrocarbon production volume. And it has a major resource base of hydrocarbons onshore and offshore, with assets in all of Russia's key hydrocarbon regions and abroad. bp's share of Rosneft hydrocarbon production in 2020 was 1,098mboe/d, compared with 1,144mboe/d in 2019.

Rosneft is a member of the Methane Guiding Principles initiative that aims to reduce methane emissions along the natural gas value chain. It reaffirmed its commitment to the 17 UN Sustainable Development Goals and the core principles of the UN Global Compact.

Rosneft is the leading Russian refining company based on throughput. It owns and operates 13 refineries in Russia and holds stakes in three refineries in Germany, one in India and one in Belarus. Rosneft refinery throughput in 2020 was 2,103mb/d, compared with 2,236mb/d in 2019.

Downstream operations include jet fuel, bunkering, bitumen and lubricants. Rosneft also owns and operates over 3,055 retail service stations in Russia and abroad. These includes Rosneft-branded sites, as well as bp-branded sites operating under a licensing agreement.

Rosneft's largest shareholder is Rosneftegaz JSC (Rosneftegaz), which is wholly owned by the Russian government. At 31 December 2020, Rosneftegaz held 40.4% (2019: 50% plus one share) of the voting share capital of Rosneft.

2020 summary

bp remains committed to our strategic investment in Rosneft, while complying with all relevant sanctions.

bp's two nominees, Bernard Looney and Bob Dudley, were elected to Rosneft's board at Rosneft's annual general meeting (AGM) in June. Bob Dudley is a chairman of the Rosneft board's Strategy and Sustainable Development Committee. At the AGM, shareholders also approved a resolution to pay a dividend. bp received a payment of $480 million, after the deduction of withholding tax, in July.

On 30 April, Rosneft completed a transaction to transfer all of its interest and cease participation in its Venezuelan businesses to a company owned by the government of the Russian Federation. In consideration, it received shares equal to a 9.6% share of its own equity. The shares are held by a 100% subsidiary of Rosneft and accounted for as treasury shares. Rosneft also has an approved programme of share buybacks under which shares are being repurchased. Those shares are also accounted for as treasury shares.

bp retains 19.75% of the voting rights at meetings of Rosneft shareholders and continues to be entitled to dividends based on that shareholding. bp's economic interest as of 31 December 2020, however, has increased to 22.03% as a result of its indirect interest in the shares held by the subsidiaries of Rosneft. bp's share of profit or loss of Rosneft reflects its economic interest.

On 14 December 2020, Rosneft announced the sale of a 49% stake in Krasgeonats to Equinor for approximately $550 million. Krasgeonats owns 12 licences for exploration and production in Eastern Siberia, including the recently launched North-Danilovskoye field.

On 28 December, Rosneft announced completion of the acquisition of 100% stakes in JSC Taimyrneftegaz and LLC Taimyrburservis, and the sale of a 10% interest in LLC Vostok Oil to Trafigura for Euro 7 billion.

In December, Rosneft announced that it has developed a 2035 Carbon Management Plan, a long-term framework for its development in the context of transitioning to a low carbon economy, including management of climate risks and identification of opportunities related to future energy demand.

2020 marked the 10th anniversary of Rosneft's participation in UN Global Compact, the world's largest sustainability initiative. In 2020, Rosneft presented its public statement regarding human rights and the Declaration on Human Rights for interacting with suppliers of goods, works and services.

In February 2021,Rosneft and bp signed a Strategic Collaboration Agreement focused on supporting carbon management and sustainability activities of both companies.

The agreement builds on bp's longstanding strategic partnership with Rosneft and will explore opportunities for new investment and collaboration in Russia across several key focus areas:

- Developing industry methodologies and standards on carbon management, including methane reduction initiatives and energy efficiency applications.
- Evaluating new projects in renewables, carbon capture and hydrogen.
- Assessing opportunities in the downstream including advanced fuels, natural forest sinks and carbon offset credits.
- Sustainable development and social investment, including biodiversity.

★ See Glossary

Environmental expenditure

			$ million
	2020	2019	2018
Operating expenditure	**531**	511	501
Capital expenditure	**241**	468	449
Clean-ups	**29**	23	31
Additions to environmental remediation provision	**297**	272	428
Increase (decrease) in decommissioning provision	**(686)**	1,045	137

Operating and capital expenditure on the prevention, control, treatment or elimination of air and water emissions and solid waste is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction that includes, for example, normal operations and maintenance expenditure. The figures for environmental operating and capital expenditure in the table are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

Environmental operating expenditure of $531 million in 2020 (2019 $511 million) showed an overall increase of 4%, with increases in BP Products and Shipping expenditure largely balanced out by a reduction in expenditure for BPX Energy.

Environmental capital expenditure of $241 million in 2020 was significantly down (2019 $468 million) largely due to decreased expenditure in the BPX Energy and BP Products North America business.

Clean-up costs were $29 million in 2020 (2019 $23 million) representing oil spill clean-up costs and other associated remediation and disposal costs. The increase compared to 2019 results largely from increased expenditure in three businesses, namely BP Pipelines (North America), Alaska and Remediation Management.

In addition to operating and capital expenditure, we also establish provisions for future environmental remediation work. Expenditure against such provisions normally occurs in subsequent periods and is not included in environmental operating expenditure reported for such periods.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The extent and cost of future environmental restoration, remediation and abatement programmes are inherently difficult to estimate. They often depend on the extent of contamination, and the associated impact and timing of the corrective actions required, technological feasibility and bp's share of liability. Though the costs of future programmes could be significant and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the group's overall results of operations or financial position.

Additions to our environmental remediation provision was similar to prior years and also reflects scope reassessments of the remediation plans of a number of our sites in the US. The charge for environmental remediation provisions in 2020 included $8 million in respect of provisions for new sites (2019 $9 million and 2018 $8 million).

In addition, we make provisions on installation of our oil and gas producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility, a provision is established that represents the discounted value of the expected future cost of decommissioning the asset.

In 2020, the net decrease in the decommissioning provision was due to a change in the discount rate and a change in cost estimate assumptions.

We undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments.

Provisions for environmental remediation and decommissioning are usually established on a discounted basis, as required by IAS 37 'Provisions, Contingent Liabilities and Contingent Assets'.

Further details of decommissioning and environmental provisions appear in Financial statements – Note 23.

Regulation of the group's business

Our businesses and operations are subject to the laws and regulations applicable in each country, state or other regional or local area in which they occur. These cover virtually all aspects of bp's activities and include matters such as licence acquisition, production rates, royalties, environmental, health and safety protection, fuel specifications and transportation, trading, pricing, anti-trust, export, taxes, and foreign exchange.

Oil and gas contractual and regulatory framework

The terms and conditions of the leases, licences and contracts under which our upstream oil and gas interests are held vary from country to country. These leases, licences and contracts are generally granted by or entered into with a government entity or state-owned or controlled company and are sometimes entered into with private property owners. Arrangements with governmental or state entities usually take the form of licences or production-sharing agreements★ (PSAs), although arrangements with private entities and the US government entities are usually by lease.

Licences (or concessions) give the holder the right to explore for, develop and produce a commercial discovery. Under a licence, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the licence holder is entitled to all production, minus any royalties that are payable in kind. A licence holder is generally required to pay production taxes or royalties, which may be in cash or in kind.

In certain countries, separate licences are required for exploration and production activities, and in some cases production licences are limited to only a portion of the area covered by the original exploration licence.

PSAs entered into with a government entity or state-owned or controlled company generally require bp (alone or with other contracting companies) to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any. Less typically, bp may explore for, develop and produce hydrocarbons under a service agreement with the host entity in exchange for reimbursement of costs and/or a fee paid in cash rather than production.

bp frequently conducts its exploration and production activities in joint arrangements★ or co-ownership arrangements with other international oil companies, state-owned or controlled companies and/or private companies. Conventionally, all costs, benefits, rights, obligations, liabilities and risks incurred in carrying out joint arrangement or co-ownership operations under a lease, licence or PSA are shared among the joint arrangement or co-owning parties according to agreed ownership interests among them. To the extent that any liabilities arise, whether to governments or third parties, or as between the joint arrangement parties or co-owners themselves, each joint arrangement party or co-owner will generally be liable to meet these in proportion to its ownership interest. In many upstream operations, a party (known as the operator) will be appointed (pursuant to a joint operating agreement) to carry out day to-day operations on behalf of the joint arrangement or co-ownership. The operator is typically one of the joint arrangement parties or a co-owner and will carry out its duties either through its own staff, or by contracting out various elements to third-party contractors or service providers. bp acts as operator on behalf of joint arrangements and co-ownerships in a number of countries.

Frequently, work (including drilling and related activities) will be contracted out to third-party service providers. The relevant contract will specify the work, the remuneration, and typically the risk allocation between the parties. Depending on the service to be provided, the contract may also contain provisions allocating risks and liabilities associated with pollution and environmental damage, damage to a well or hydrocarbon reservoirs and for claims from third parties or other losses. The allocation of those risks vary among contracts and are determined through negotiation between the parties.

★ See Glossary

In general, bp incurs income tax on income generated from production activities (whether under a licence or PSA). In addition, depending on the area, bp's production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed on oil and gas production profits and activities may be substantially higher than those imposed on other activities, for example in Abu Dhabi, Angola, Egypt, Norway, the UK, the US, Russia and Trinidad & Tobago.

Sustainable finance

On 12 July 2020, elements of Regulation (EU) 2020/852 on the establishment of a framework to facilitate sustainable investment (Taxonomy Regulation) entered into force and form part of UK law pursuant to the European Union (Withdrawal) Act of 2018. The Taxonomy Regulation establishes a classification system for determining whether an economic activity is environmentally sustainable for the purposes of guiding investors in financial products which are marketed as promoting environmental objectives. Although the UK government has expressed its intention to retain the overall taxonomy framework and objectives as set forth in the Taxonomy Regulation, it is not yet clear to what extent UK law will align with elements of the Taxonomy Regulation which were not in effect as of the end of the Brexit transition period on 31 December 2020. bp may in the future be required to comply with the Taxonomy Regulation or any parallel or similar legislation which may come into force in the UK.

Greenhouse gas regulation

In December 2015, nearly 200 nations at the United Nations climate change conference in Paris (COP21) agreed the Paris Agreement which aims to hold the increase in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. Signatories aim to reach global peaking of greenhouse gas (GHG) emissions as soon as possible and to undertake rapid reductions thereafter, so as to achieve a balance between human caused emissions and removals by sinks of GHGs in the second half of this century. The Paris Agreement commits all signatories to submit Nationally Determined Contributions (NDCs) (i.e. pledges or plans of climate action) and pursue domestic measures aimed at achieving the objectives of their NDCs. Signatories are required to submit revised NDCs every five years, and the revised NDC's are expected to be more ambitious with each revision. Global assessments of progress will occur every five years, starting in 2023.

Agreement of rules which could enable international carbon trading to assist in meeting NDCs, has been deferred to COP26 which is expected to take place in Glasgow, Scotland in November 2021. More stringent national and regional measures relating to the transition to a lower carbon economy, such as the UK's 2050 net zero carbon emissions commitment, can be expected in the future. These measures could increase bp's production costs for certain products, increase compliance and litigation costs, increase demand for competing energy alternatives or products with lower-carbon intensity, and affect the sales and specifications of many of bp's products. Further, such measures could lead to constraints on production and supply and access to new reserves, particularly due to the long term nature of many of bp's projects. Certain current and announced GHG measures and developments potentially affecting bp's businesses in various markets in which bp operates are summarized below. For information on steps that bp is taking in relation to climate change issues and for details of bp's GHG reporting, see Sustainability – Net zero aims on page 49.

United States

In the US, bp's operations are affected by GHG regulation in a number of ways. The federal Clean Air Act (CAA), for example, regulates air emissions, permitting, fuel specifications and other aspects of our production, refining, distribution and marketing activities.

Environmental Protection Agency (EPA) regulations aimed at limiting methane emissions from new and modified sources in the oil and natural gas sector in the US by 40-45% from 2012 levels by 2025 were the subject of an August 2020, EPA final 'policy rule' intended to significantly revise that regulation. This rule is the subject of litigation in the D.C. Circuit. In addition, the Bureau of Land Management (BLM) in 2018 issued a new waste prevention rule which rescinded the prior 2017 rule regarding methane regulation on federal lands. While litigation around both rules is expected to continue, the Biden administration has taken executive action with respect to Federal regulations promulgated during the Trump administration relating to climate change, including a review of both of these rules. Other EPA GHG regulations which may affect electricity generation practices and prices and have an impact on the market for fuels used to generate electricity and on renewable energy installations are in flux due to changes in approach between presidential administrations, as well as lawsuits challenging proposed regulations. In 2019, the EPA issued the final Affordable Clean Energy (ACE) Rule, which is intended to address GHG emissions from certain existing sources in the electricity sector, and which is intended to replace the Obama administration's Clean Power Plan (CPP). A number of lawsuits have been filed regarding the legality of the ACE Rule and the repeal of the CPP regulations, and on 19 January 2021, the DC Circuit struck down the ACE rule in its entirety. The Biden administration may develop new regulations that more closely mirror the CPP.

The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 impose the Renewable Fuel Standard (RFS), requiring transportation fuel sold in the United States to contain a minimum volume of renewable fuels. Certain state initiatives impose lower GHG emissions thresholds for transportation fuels (e.g., in California and Oregon). In 2020, EPA changed its approach to Small Refinery Exemptions based on court activity. EPA is behind schedule in setting RFS requirements for 2021 and we expect the administration to begin the process of setting 2023 and beyond volumes in 2021 as well.

The GHG mandatory reporting rule, requires operators of certain facilities and producers and importers/exporters of petroleum products to file annual GHG emissions reports with the EPA quantifying direct emissions from affected facilities, as well as volumes of petroleum products, certain natural gas liquids and GHG products and notional GHG emissions as if these products were fully combusted.

A number of states, municipalities and regional organizations have responded to current and proposed federal changes easing environmental regulation with separate initiatives that affect our US operations. For example, the California cap and trade programme started in January 2012 and expanded to cover emissions from transportation fuels in 2015. The State of Washington has adopted a carbon cap rule although the state's Supreme Court has modified the rule to exclude coverage of sales and distribution of petroleum fuels. We expect a number of states to advance economy-wide and transport/fuels specific regulations in 2021.

Our US businesses are subject to increased GHG and other environmental requirements and regulatory uncertainty, including that the Biden or any future US administrations could revise or revoke current or prior administration programs, as well as increased expenditures in having to comply with numerous diverse and non-uniform regulatory initiatives at the state and local level.

US fuel markets are affected by EPA regulation of light, medium and heavy duty vehicle emissions (both fuel economy and tailpipe standards) as well as for non-road engines and vehicles and certain large GHG stationary emission sources. California also imposes Low Emission Vehicle (LEV) and Zero Emission Vehicle (ZEV) standards on vehicle manufacturers and a number of other states, as allowed by CAA authority, have adopted standards identical to California's standards. These regulations may impact bp's product mix and demand for particular products in those states. In August 2020, California also entered into agreements with several carmakers to meet more demanding emissions standards in California.

In 2019 the Trump administration issued the Safer Affordable Fuel-Efficient Vehicles rule rolling back the Obama administration's fuel economy and tailpipe carbon dioxide emissions standards for passenger cars and light trucks covering model years (MY) 2021 through 2026 by locking in the 2020 standards until 2026. It has also proposed eliminating the waiver allowing California to set its own LEV and ZEV standards and for other states to adopt those standards. Litigation challenging these regulations is ongoing although the Biden administration is expected to restore the California waiver and commence rulemaking to reinstate the stricter fuel economy and tailpipe carbon dioxide emissions standards.

In January 2020, EPA solicited on a proposed rulemaking known as the Cleaner Trucks Initiative. The rule would, among other things, establish new emission standards for oxides of nitrogen (NOx) and other pollutants for highway heavy-duty engines and the Biden administration is expected to modify and continue this proposed rulemaking. California has also adopted a "Heavy-Duty Low NOx Omnibus Regulation" which will require manufacturers to comply with stricter emissions standards. The rule is being phased in, with the first phase effective in 2024. bp continues to monitor these rules for implications for fuels.

European Union

- The EU and its member states have adopted various measures seeking to reduce GHG emissions and encourage renewables. A set of regulatory measures adopted by the EU include: a collective national reduction target for emissions not covered by the EU Emissions Trading System (EU ETS) Directive; binding national renewable energy targets (including targets in the transport sector) under the Renewable Energy Directive; and a legal framework to promote carbon capture and storage.
- In 2014, EU leaders adopted a climate and energy framework setting targets for the year 2030 including at least 40% reductions in GHG emissions from 1990 levels and in December 2020 the Council agreed an increase to a 55% reductions target from 1990 levels which is pending before the European Parliament.
- In December 2019, the European Commission proposed an ambitious 'European Green Deal'. These proposals, which require formal approval by EU Member States to be adopted and include climate neutrality and increased GHG reduction targets, tightening of the emissions caps in the EU ETS, extending the EU ETS to include the maritime sector and reducing allowances allocated to airlines, implement a carbon border tax adjustment and harmonise energy taxation across the EU Member States.
- In October 2020 the European Commission presented an EU strategy to reduce methane emissions. The strategy sets out measures to cut methane emissions in Europe and internationally. It presents legislative and non-legislative actions in the energy, agriculture and waste sectors, which account for around 95% of methane emissions associated with human activity worldwide.
- European regulations also establish passenger car performance standards for CO2 tailpipe emissions (European Regulation (EC) No 443/2009). By 2021, the European passenger fleet emissions target for new vehicles will be 95 grams of CO2 per kilometre. This target will be achieved by manufacturing fuel efficient vehicles and vehicles using alternative, low carbon fuels such as hydrogen and electricity.
- In 2019, the European Parliament and the Council adopted Regulation (EU) 2019/631 setting CO2 emission performance standards for new passenger cars and for new light commercial vehicles (vans) in the EU for the period after 2020. From a 2021 baseline, it requires EU fleet-wide reductions of 15% by 2025 and 37.5% by 2030 for passenger cars, and 15% by 2025 and 31% by 2030 for new light commercial vehicles.
- The EU Fuel Quality Directive affects our production and marketing of transport fuels including mandating reductions in the life cycle GHG emissions per unit of energy and tighter environmental fuel quality standards for petrol and diesel.
- Germany is expected to launch a national emissions trading system in 2021 for transport and heating fuels. Impacted fuel suppliers in Germany will pay a fixed price for emissions certificates of EUR 25 per tonne CO2 in 2021 rising to EUR 55 per tonne by 2025. In 2026, emissions certificates will be auctioned but with prices limited between EUR 55 and EUR 65 per tonne CO2 emitted. A review of the system is expected to take place in 2025 to determine the position beyond 2026.

Other

- In December 2020 the UK Government announced a targeted reduction in the UK's GHG emissions of at least 68% by 2030, compared to 1990 levels. The UK also announced an emissions trading system from 1 January 2021 onwards which would include the same installations in the UK that were previously subject to the EU ETS.
- China is operating emission trading pilot programmes in five cities and three provinces. One of bp's subsidiaries★ and one of bp's joint venture★ companies in China are participating in these schemes. China launched its national emissions trading market (National ETS), initially covering the power sector only, politically in 2017. On 31 December 2020, China promulgated the national regulation on National ETS which became effective on 1 February 2021, when the National ETS was officially launched.
- China has also adopted more stringent vehicle tailpipe emission standards and vehicle efficiency standards to address air pollution and GHG emissions. These standards will have an impact on transportation fuel product mix and overall demand. In addition, China has also introduced a mandate for sales of new energy vehicles (NEVs) commencing in 2020. This has been accelerating NEV penetration into the light vehicle sector and impact light fuel demand.

Other environmental regulation

In addition to GHG regulations including current and proposed fuel and product specifications and emission controls (including control of vehicle emissions) referred to above, climate change programmes and regulation of unconventional oil and gas extraction under a number of environmental laws may have a significant effect on the production, sale and profitability of many of bp's products.

Environmental laws also require bp to remediate and restore areas affected by the release of hazardous substances or hydrocarbons associated with our operations or properties. These laws may apply to sites that bp currently owns or operates, sites that it previously owned or operated, or sites used for the disposal of its and other parties' waste. See Financial Statements – Note 23 for information on provisions for environmental restoration and remediation.

A number of pending or anticipated governmental proceedings against certain bp group companies under environmental laws could result in monetary or other sanctions. Group companies are also subject to environmental claims for personal injury and property damage alleging the release of, or exposure to, hazardous substances. The costs associated with future environmental remediation obligations, governmental proceedings and claims could be significant and may be material to the results of operations in the period in which they are recognized. We cannot accurately predict the effects of future developments, such as stricter environmental laws and regulations or enforcement policies, or future events at our facilities, on the group, and there can be no assurance that material liabilities and costs will not be incurred in the future. For a discussion of the group's environmental expenditure, see page 321 and for a discussion of legal proceedings, see page 226.

Significant legislation and regulation in the US and the EU affecting our businesses and profitability, in addition to those referred to above, include the following:

United States

- The Clean Water Act regulates wastewater and other effluent discharges from bp's facilities, and bp is required to obtain discharge permits, install control equipment and implement operational controls and preventative measures.
- The Resource Conservation and Recovery Act regulates the generation, storage, transportation and disposal of wastes associated with our operations and can require corrective action at locations where such wastes have been disposed of or released. bp has incurred, or is likely to incur, liability under RCRA or similar state laws in connection with sites bp operates or previously operated.
- The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) can, in certain circumstances, impose the entire cost of investigation and remediation on a party who owned or operated a site contaminated with a hazardous substance, or who arranged for disposal of a hazardous substance at a site. bp has incurred, or is likely to incur, liability under CERCLA or similar state laws, including costs attributed to insolvent or unidentified parties. bp is also subject to claims for remediation costs and natural resource damages under CERCLA and other federal and state laws.

- The Emergency Planning and Community Right-to-Know Act requires reporting on the storage, use and releases of certain quantities of listed hazardous substances to designated government agencies.
- The Toxic Substances Control Act (TSCA) regulates bp's manufacture, import, export, sale and use of chemical substances and products. In addition, EPA has revised processes and procedures for prioritisation of existing chemicals for risk evaluation, assessment and management. Agency actions and announcements are monitored regularly to identify developments with potential impacts on chemical substances important to bp products and operations. Thus far, bp has identified two substances for specific ongoing monitoring of developments and impacts.
- The Occupational Safety and Health Act imposes workplace safety and health requirements on bp operations along with significant process safety management obligations, requiring continuous evaluation and improvement of operational practices to enhance safety and reduce workplace emissions at gas processing, refining and other regulated facilities.
- The Oil Pollution Act 1990 (OPA) imposes operational requirements, liability standards and other obligations governing the transportation of petroleum products in US waters. States may impose additional obligations. Alaska and the West Coast states currently have the most demanding state requirements.
- The Outer Continental Shelf Land Act, the Mineral Leasing Act and other statutes give the Department of Interior (DOI) and the BLM authority to regulate operations and air emissions, including equipment and testing, on offshore and onshore operations on federal lands subject to DOI authority.
- The Endangered Species Act (ESA) and Marine Mammal Protection Act protect certain species' habitats from adverse human impacts by restricting operations or development at certain times and in certain places. In 2020, the US Fish and Wildlife Service published two proposed rules impacting designations under ESA, but on 20 January 2021 the Biden administration announced a review of these proposed rules reducing the scope of habitat protections.

European Union

- The Industrial Emissions Directive (IED) 2010 provides the framework for granting permits for major industrial sites. It lays down rules on integrated prevention and control of air, water and soil pollution arising from industrial activities. As part of the IED framework, additional emission limit values are informed by sector specific and cross-sector Best Available Technology (BAT) Conclusions. These include the BAT Conclusions for the refining sector, for large combustion plants as well as common wastewater and waste gas treatment and management systems in the chemical sector. These may require bp to further reduce its emissions, particularly its air and water emissions.
- The EU Regulation on substances that deplete the ozone layer 2009 (ODS Regulation) requires companies to reduce the use of ozone depleting substances (ODSs) and phase out use of certain ODSs. bp continues to replace ODSs in refrigerants and/or equipment in the EU and elsewhere, in accordance with the Montreal Protocol and related legislation.
- The Medium Combustion Plants Directive 2015 (MCPD) regulates sulphur dioxide (SO2), nitrogen oxides (NOx) and particulates emissions and monitoring of carbon monoxide (CO) emissions from certain mid-size plants. It applies to new plants and by 2025 or 2030 to existing plants, depending on their size.
- The National Emission Ceilings Directive 2016 (NECD) introduces stricter emissions limits from 2020 and 2030, with new indicative national targets applying from 2025. NECD has been implemented in the UK by the National Emission Ceilings Regulations 2018. Each EU Member State was also required to produce a National Air Pollution Control Programme setting out the measures it will take to ensure compliance with the 2020 and 2030 reduction commitments.
- The EU Registration, Evaluation Authorization and Restriction of Chemicals (REACH) Regulation 2006 requires registration of chemical substances manufactured in or imported into the EU, together with the submission of relevant hazard and risk data. REACH affects our manufacturing or trading/import operations in the EU. bp maintains compliance by checking whether imports are covered by the registrations of non-EU suppliers' representatives, preparing and submitting registration dossiers to cover new manufactured and imported substances, and updating previously submitted registrations as required. Some substances registered previously, including substances supplied to us by third parties for our use, are now subject to evaluation and review for potential authorization or restriction procedures, and possible banning, by the European Chemicals Agency and EU Member State authorities. In addition, bp's facilities and operations in several EU countries continue to undergo REACH compliance inspections by the competent authority for the respective EU Member State. An amendment to the Annex of the Regulation on classification, labelling and packaging of substances and mixture (CLP Regulation) requires harmonized notification of information on hazardous materials (certain lubricant and fuel formations) to EU Member State poison centres. The uniform notification rules apply as of January 2020 for consumer products, from 2021 for professional and 2024 for industrial uses.
- The EU Offshore Safety Directive was adopted in 2013. Its purpose is to introduce a harmonized regime aimed at reducing the potential environmental, health and safety impacts of the offshore oil and gas industry throughout EU waters. The Directive has been implemented in the UK primarily through the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015.
- The Water Framework Directive (WFD) published in 2000 aims to protect the quantity and quality of ground and surface waters of the EU Member States. The implementation in the EU Member States is still ongoing, planned to be finalised by 2027. A Fitness Check (comprehensive policy evaluation) of the EU Water Legislation launched in 2019 concluded that the WFD is broadly fit for purpose. Future proceedings on the determination of pollutants/priority substances as well as environmental quality standards in line with the WFD may require additional compliance efforts and increased costs for managing freshwater withdrawals and discharges from bp's EU operations.

United Kingdom

Following the UK's exit from the European Union on 31 January 2020, the UK entered a transition period which ran until 31 December 2020. During the transition period, most EU law continued to apply to the UK and therefore to bp's UK business during that period. From 1 January 2021, operative EU laws were retained in UK law by the European Union (Withdrawal) Act 2018. The vast majority of environment related statutory instruments passed by the UK Government in anticipation of Brexit have included no substantive changes to the current EU underlying regime, but rather seek to make the amendments required to allow their continued operation after the transition period. The UK Government's Environment Bill and 25 Year Plan will be central to the UK's environmental regime going forward but further changes are as yet uncertain.

Other countries and regions

Regulations governing the discharge of treated water have also been developed in countries outside of the US and EU. This includes regulations in Trinidad and Angola which impacts bp's production operations in those countries. In Trinidad, bp commissioned a new waste water treatment plant in 2020 to meet consent levels agreed with the regulators to apply water discharge rules arising from the Certificate of Environmental Clearance (CEC) Regulations 2001 and associated Water Pollution Rules 2007. In Angola, bp has upgraded produced water treatment systems to meet revised oil in water limits for produced water discharge under Executive Decree ED 97-14.

The Abidjan Convention, along with the Additional Protocol published in 2012, sets environmental quality standards for the discharge of chemicals to the marine environment. The convention and associated protocols has been ratified by 19 African nations including Senegal and Mauritania. bp is currently constructing the offshore facilities to include produced water management systems to meet the environmental quality standards for our future gas operations in Mauritania and Senegal.

Environmental maritime regulations

bp's shipping operations are subject to extensive national and international regulations governing operations, training, pollution prevention, liability, and insurance. These include:

- Liability and spill prevention and planning requirements governing, among others, tankers, barges, and offshore facilities are imposed by OPA in US waters. OPA also mandates a levy on imported and domestically produced oil to fund oil spill responses. Some states, including Alaska, Washington, Oregon and California, impose additional liability for oil spills. Outside US territorial waters, bp shipping tankers are subject to international pollution prevention, liability, spill response and preparedness regulations developed through the UN's International Maritime Organization (IMO), including the International Convention on Civil Liability for Oil Pollution Damage, the International Convention for the Prevention of Pollution from Ships (MARPOL), the International Convention on Oil Pollution, Preparedness, Response and Co-operation, and the International Convention on Civil Liability for Bunker Oil Pollution Damage. In April 2010, the Hazardous and Noxious Substance (HNS) Protocol 2010 was adopted to address issues that have inhibited ratification of the International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea 1996. As at 31 December 2020, the HNS Convention had not entered into force.
- A global sulphur cap of 0.5% applies to marine fuel under MARPOL. In order to comply, ships either need to consume low sulphur marine fuels, operate on alternative low sulphur fuels such as LNG or implement approved abatement technology to enable them to meet the low sulphur emissions requirements while continuing to use higher sulphur fuel. This global cap does not alter the lower limits that apply in the sulphur oxides Emissions Control Areas established by the IMO.
- The Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR), aims to protect the marine environment of the North-East Atlantic. The OSPAR 2012 Recommendation and Guideline for the implementation of a risk-based approach to the management of produced water discharges from offshore installations in the North Sea supports a key goal of working towards eliminating harmful discharges. In 2020 the International Association of Oil and Gas Producers issued a report "Oil And Gas Risk Based Assessment of Offshore Produced Water Discharges" which presents industry good practice and aims to broaden the understanding and acceptance of Risk Based Assessment (RBA) techniques internationally and improve consistency in the application of assumptions, levels of conservatism, and selection of risk endpoints.

To meet its financial responsibility requirements, bp Shipping maintains marine oil pollution liability insurance in respect of its operated ships to a maximum limit of $1 billion for each occurrence through mutual insurance associations (P&I Clubs), although there can be no assurance that a spill would necessarily be adequately covered by insurance or that liabilities would not exceed insurance recoveries.

International trade sanctions

During the period covered by this report, non-US subsidiaries★, or other non-US entities of BP, conducted limited activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of Terrorism or otherwise subject to US and EU sanctions (Sanctioned Countries). Sanctions restrictions continue to be insignificant to the group's financial condition and results of operations. BP monitors its activities with Sanctioned Countries, persons from Sanctioned Countries and individuals and companies subject to US, EU and (following the end of the Brexit transition period) UK sanctions and seeks to comply with applicable sanctions laws and regulations.

BP has a 28.83% interest in and operates the Shah Deniz field in Azerbaijan (Shah Deniz), has a 28.83% interest in and performs some operations for a related gas pipeline entity, South Caucasus Pipeline Company Limited (SCPC), and has a 23% non-operating interest in a related gas marketing entity, Azerbaijan Gas Supply Company Limited (AGSC). Naftiran Intertrade Co. Limited and NICO SPV Limited (collectively, NICO) have a 10% non-operating interest in each of Shah Deniz and SCPC and an 8% non-operating interest in AGSC. Shah Deniz, SCPC and AGSC continue in operation as they were excluded from the application of US sanctions and fall within the exception for certain natural gas projects under Section 603 of the Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA).

On 3 December 2018 BP entered into an agreement with, among others, SOCAR and NICO pursuant to which SOCAR pays to BP Exploration (Shah Deniz) Limited (BPXSD), as the Shah Deniz operator, compensation for NICO's waiver of its right to lift its share of Shah Deniz condensate. Such amounts are used to cover cash calls to NICO in respect of operating costs due from NICO to BPXSD. On 26 October 2020, OFAC issued an amended licence in relation to these arrangements.

Following the imposition in 2011 of further US and EU sanctions against Syria, BP terminated all sales of crude oil and petroleum products into Syria, though BP continues to supply aviation fuel to non-governmental Syrian resellers outside of Syria.

BP has a joint arrangement in Cuba which imports, manufactures, markets and sells lubricants.

During 2014, the US and the EU imposed sanctions on certain sectors of the Russian economy (energy, finance and defence/military) and on certain individuals and entities, including Rosneft. These sectoral sanctions include restrictions on the provision of financial assistance, technical assistance, and services in relation to exploration and production activity in deep water, shale, and offshore Arctic.

Additional US sanctions have been imposed since 2014, broadening the scope of US sanctions on Russia-related activity to include certain international deep water, shale, and offshore Arctic projects as well as the provision of goods and services for Russian energy export pipelines. As of 1 January 2021, as a result of the UK's exit from the EU, the UK has also imposed Russian-related sanctions, which are broadly similar to existing EU sanctions.

We are not aware of any material adverse effect on our current income and investment in Russia or elsewhere as a consequence of these sanctions.

BP maintains bank accounts and has registered and paid required fees to maintain registrations of patents and trademarks in certain Sanctioned Countries.

BP has equity interests in non-operated joint arrangements★ with air fuel sellers, resellers, and fuel delivery services around the world.

From time to time, the joint arrangement operator or other partners may sell or deliver fuel to airlines from Sanctioned Countries or flights to Sanctioned Countries, without BP's involvement.

BP has no control over the activities non-controlled associates★ may undertake in Sanctioned Countries or with persons from Sanctioned Countries.

Disclosure pursuant to ITRA Section 219

To our knowledge, none of BP's activities, transactions or dealings are required to be disclosed pursuant to ITRA Section 219, with the following possible exceptions.

On 17 July 2018, BP Iran Limited terminated its lease of an office in Tehran. The office had been used for administrative activities. In 2020, taxes with an aggregate US dollar equivalent value of approximately $20,000 were paid from a BP trust account held with Tadvin Co. to Iranian public entities. No gross revenues or net profits were attributable to these activities.

BP has a 29.3% interest in Middle East Lubricants Company LLC (Melubco), which is established and manufactures lubricants in the United Arab Emirates. In May 2020, Melubco successfully appealed an Iranian court judgment obtained against it in absentia for non-payment of shipping fees. The applicant, an Iranian shipping company, had confused Melubco with an unrelated, but similarly named, Iranian entity. In order to do so, Melubco paid court filing fees equivalent to approximately $3,000 to the Tehran Judicial Services Office. Melubco does not, and has never, done business in Iran.

Material contracts

On 4 April 2016 the district court approved the Consent Decree among BP Exploration & Production Inc., BP Corporation North America Inc., BP p.l.c., the United States and the states of Alabama, Florida, Louisiana, Mississippi and Texas (the Gulf states) which fully and finally resolved any and all natural resource damages (NRD) claims of the United States, the Gulf states, and their respective natural resource trustees and all Clean Water Act (CWA) penalty claims, and certain other claims of the United States and the Gulf states.

Concurrently, the definitive Settlement Agreement that bp entered into with the Gulf states (Settlement Agreement) with respect to State claims for economic, property and other losses became effective.

bp has filed the Consent Decree and the Settlement Agreement as exhibits to its Annual Report on Form 20-F 2020 filed with the SEC. For further details of the Consent Decree and the Settlement Agreement, see Legal proceedings in bp *Annual Report and Form 20-F 2015*.

Property, plant and equipment

bp has freehold and leasehold interests in real estate and other tangible assets in numerous countries, but no individual property is significant to the group as a whole. For more on the significant subsidiaries★ of the group at 31 December 2020 and the group percentage of ordinary share capital see Financial statements – Note 37. For information on significant joint ventures★ and associates★ of the group see Financial statements – Notes 16 and 17.

Related-party transactions

Transactions between the group and its significant joint ventures and associates are summarized in Financial statements – Note 16 and Note 17. In the ordinary course of its business, the group enters into transactions with various organizations with which some of its directors or executive officers are associated. Except as described in this report, the group did not have any material transactions or transactions of an unusual nature with, and did not make loans to, related parties in the period commencing 1 January 2020 to 2 March 2021.

Corporate governance practices

In the US, bp ADSs are listed on the New York Stock Exchange (NYSE). The significant differences between bp's corporate governance practices as a UK company and those required by NYSE listing standards for US companies are listed as follows:

Independence

In 2020 bp continued to apply its board governance principles. These reflect the UK Corporate Governance Code approach to corporate governance. As such, the way in which bp makes determinations of directors' independence differs from the NYSE rules. As set out on page 88, from 1 January 2021 bp has adopted terms of reference for the board and each of its committees.

bp's board governance principles require that all non-executive directors be determined by the board to be 'independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement'. The bp board has determined that, in its judgement, all of the non-executive directors are independent. In doing so, however, the board did not explicitly take into consideration the independence requirements outlined in the NYSE's listing standards.

Committees

bp has a number of board committees that are broadly comparable in purpose and composition to those required by NYSE rules for domestic US companies. For instance, bp has a remuneration (rather than a compensation) committee. bp also has an audit committee, which NYSE rules require for both US companies and foreign private issuers. These committees are composed solely of non-executive directors whom the board has determined to be independent, in the manner described above.

The bp board governance principles prescribe the composition, main tasks and requirements of each of the committees (see the board committee reports on pages 92-102 and 105). Therefore, during 2020 bp did not have separate charters for each committee. As from the start of 2021 each of the board committees has adopted its own terms of reference which set out their respective roles and responsibilities.

Under US securities law and the listing standards of the NYSE, bp is required to have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act and Section 303A.06 of the NYSE Listed Company Manual. bp's audit committee complies with these requirements. The bp audit committee does not have direct responsibility for the appointment, reappointment or removal of the independent auditors. Instead, it follows the UK Companies Act 2006 and the UK Corporate Governance code 2018 by making recommendations to the board on these matters for it to put forward for shareholder approval at the AGM.

One of the NYSE's additional requirements for the audit committee states that at least one member of the audit committee is to have 'accounting or related financial management expertise'. The board determined that Brendan Nelson possesses such expertise and also possesses the financial and audit committee experiences set forth in both the UK Corporate Governance Code and SEC rules (see Audit committee report on page 94). Mr Nelson is the audit committee financial expert as defined in Item 16A of Form 20-F.

Shareholder approval of equity compensation plans

The NYSE rules for US companies require that shareholders must be given the opportunity to vote on all equity-compensation plans and material revisions to those plans. bp complies with UK requirements that are similar to the NYSE rules. The board, however, does not explicitly take into consideration the NYSE's detailed definition of what are considered 'material revisions'.

Code of ethics

The NYSE rules require that US companies adopt and disclose a code of business conduct and ethics for directors, officers and employees. bp has adopted a code of conduct, which applies to all employees and members of the board, and has board governance principles that address the conduct of directors. In addition bp has adopted a code of ethics for senior financial officers as required by the SEC. bp considers that these codes and policies address the matters specified in the NYSE rules for US companies.

Code of ethics

The company has adopted a code of ethics for its group chief executive, chief financial officer, group controller, group head of audit and chief accounting officer as required by the provisions of Section 406 of the Sarbanes-Oxley Act of 2002 and the rules issued by the SEC. There have been no waivers from the code of ethics relating to any officers.

bp also has a code of conduct, which is applicable to all employees, officers and members of the board. This was updated (and published) in July 2014.

Controls and procedures

Evaluation of disclosure controls and procedures

The company maintains 'disclosure controls and procedures', as such term is defined in Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including the company's group chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, our management, including the group chief executive and chief financial officer, recognize that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud within the company, if any, have been detected. Further, in the design and evaluation of our disclosure controls and procedures our management necessarily was required to apply its judgement in evaluating the costs and benefits of possible control and procedure design options. Also, we have investments in unconsolidated entities. As we do not control these entities, our disclosure controls and procedures with respect to such entities are necessarily substantially more limited than those we maintain with respect to our consolidated subsidiaries★. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. The company's disclosure controls and procedures have been designed to meet, and management believes that they meet, reasonable assurance standards.

The company's management, with the participation of the company's group chief executive and chief financial officer, has evaluated the effectiveness of the company's disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the group chief executive and chief financial officer have concluded that the company's disclosure controls and procedures were effective at a reasonable assurance level.

Management's report on internal control over financial reporting

Management of bp is responsible for establishing and maintaining adequate internal control over financial reporting. bp's internal control over financial reporting is a process designed under the supervision of the principal executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of bp's financial statements for external reporting purposes in accordance with IFRS.

As of the end of the 2020 fiscal year, management conducted an assessment of the effectiveness of internal control over financial reporting in accordance with the criteria 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. Based on this assessment, management has determined that bp's internal control over financial reporting as of 31 December 2020 was effective.

The company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of bp; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of bp's assets that could have a material effect on our financial statements. bp's internal control over financial reporting as of 31 December 2020 has been audited by Deloitte LLP, an independent registered public accounting firm, as stated in their report appearing on page 154 of bp *Annual Report and Form 20-F 2020*.

Changes in internal control over financial reporting

There were no changes in the group's internal control over financial reporting that occurred during the period covered by the Form 20-F that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Principal accountant's fees and services

The audit committee has established policies and procedures for the engagement of the independent registered public accounting firm, Deloitte LLP, to render audit and certain assurance services. The policies provide for pre-approval by the audit committee of specifically defined audit, audit-related, non-audit and other services that are not prohibited by regulatory or other professional requirements. Deloitte is engaged for these services when its expertise and experience of bp are important. Most of this work is of an audit nature. The committee regularly reviews the policy, including in 2020, when it was updated to reflect changes resulting from the FRC Ethical Standard (December 2019).

Under the policy, pre-approval is given for specific services within the following categories: advice on accounting, auditing and financial reporting matters; internal accounting and risk management control reviews (excluding any services relating to information systems design and implementation); non-statutory audit; project assurance and advice on business and accounting process improvement (excluding any services relating to information systems design and implementation relating to bp's financial statements or accounting records); provision of, or access to, Deloitte publications, workshops, seminars and other training materials; provision of reports from data gathered on non-financial policies and information; provision of the independent third party audit in accordance with US Generally Accepted Government Auditing Standards, over the company's Conflict Minerals Report – where such a report is required under the SEC rule 'Conflict Minerals', issued in accordance with Section 1502 of the Dodd Frank Act; and assistance with understanding non-financial regulatory requirements. bp operates a two-tier system for audit and non-audit services. For audit related services, the audit committee has a pre-approved aggregate level, within which specific work may be approved by management. Non-audit services are pre-approved for management to authorize per individual engagement, but above a defined level must be approved by the chairman of the audit committee or the full committee. In response to the revised regulatory guidelines of the UK Financial Reporting Council, the audit committee reviewed and updated its policies with effect from 1 January 2017 and in 2018 further updated its policies to clarify the engagement of the incoming auditor, Deloitte, and the outgoing auditor Ernst & Young to ensure independence. The defined maximum level for pre-approval has been reduced in line with FRC guidance on 'non-trivial' engagements. The audit committee has delegated to the chairman of the audit committee authority to approve permitted services provided that the chairman reports any decisions to the committee at its next scheduled meeting. Any proposed service not included in the approved service list must be approved in advance by the audit committee chairman and reported to the committee, or approved by the full audit committee in advance of commencement of the engagement.

The audit committee evaluates the performance of the auditor each year. The audit fees payable to Deloitte are reviewed by the committee in the context of other global companies for cost effectiveness. The committee keeps under review the scope and results of audit work and the independence and objectivity of the auditor. External regulation and bp policy requires the auditor to rotate its lead audit partner every five years. See Financial statements – Note 36 and Audit committee report on page 94 for details of fees for services provided by the auditor.

Directors' report information

This section of bp *Annual Report and Form 20-F 2020* forms part of, and includes certain disclosures which are required by law to be included in, the Directors' report.

Indemnity provisions

In accordance with BP's Articles of Association, on appointment each director is granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report. In respect of those liabilities for which directors may not be indemnified, the company maintained a directors' and officers' liability insurance policy throughout 2020. During the year, a review of the terms and scope of the policy was undertaken as part of the annual renewal. Although their defence costs may be met, neither the company's indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly. Certain subsidiaries★ are trustees of the group's pension schemes. Each director of these subsidiaries is granted an indemnity from the company in respect of liabilities incurred as a result of such a subsidiary's activities as a trustee of the pension scheme, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report.

★ See Glossary

Financial risk management objectives and policies

The disclosures in relation to financial risk management objectives and policies, including the policy for hedging, are included in How we manage risk on page 64, Liquidity and capital resources on page 306 and Financial statements – Notes 29 and 30.

Exposure to price risk, credit risk, liquidity risk and cash flow risk

The disclosures in relation to exposure to price risk, credit risk, liquidity risk and cash flow risk are included in Financial statements – Note 29.

Important events since the end of the financial year

Disclosures of the particulars of the important events affecting bp which have occurred since the end of the financial year are included in the Strategic report as well as in other places in the Directors' report.

Likely future developments in the business

An indication of the likely future developments in the business of the company is included in the Strategic report.

Research and development

Indications of our activities in the field of research and development are provided throughout the Strategic report and the Directors' report including examples on pages 16 (developing next-gen mobility solutions), 17 (driving digital innovation including through bp ventures and Launchpad), 19 (partnering to develop a project to produce hydrogen from water), 36 (innovation and engineering) and 63 (collaborating with universities and academic research). See also page 183 for our expenditure on research and development.

Branches

As a global group our interests and activities are held or operated through subsidiaries, branches, joint arrangements★ or associates★ established in – and subject to the laws and regulations of – many different jurisdictions.

Employees

Disclosures in respect of how the directors have engaged with employees and had regard to their interests are included in How the board has engaged with shareholders, the workforce and other stakeholders on page 86 and section 172 statement on pages 63, 82 and 83.

The disclosures concerning policies in relation to the employment of disabled persons and employee involvement are included in Sustainability – People and society on page 57.

Employee share schemes

Certain shares held as a result of participation in some employee share plans carry voting rights. Voting rights in respect of such shares are exercisable via a nominee. Dividend waivers are in place in respect of unallocated shares held in employee share plan trusts.

Suppliers, customers and others

Disclosures in respect of how the directors have engaged with suppliers, customers and others in business relationships with the company are included in How the board has engaged with shareholders, the workforce and other stakeholders on page 86 and section 172 statement on pages 63, 82 and 83.

Change of control provisions

On 5 October 2015, the United States lodged with the district court in MDL 2179 a proposed Consent Decree between the United States, the Gulf states, BP Exploration & Production Inc., BP Corporation North America Inc. and BP p.l.c., to fully and finally resolve any and all natural resource damages claims of the United States, the Gulf states and their respective natural resource trustees and all Clean Water Act penalty claims, and certain other claims of the United States and the Gulf states. Concurrently, bp entered into a definitive Settlement Agreement with the five Gulf states (Settlement Agreement) with respect to state claims for economic, property and other losses. On 4 April 2016, the district court approved the Consent Decree, at which time the Consent Decree and Settlement Agreement became effective. The federal government and the Gulf states may jointly elect to accelerate the payments under the Consent Decree in the event of a change of control or insolvency of BP p.l.c., and the Gulf states individually have similar acceleration rights under the Settlement Agreement. For further details of the Consent Decree and the Settlement Agreement, see Legal proceedings in *BP Annual Report and Form 20-F 2015*.

Greenhouse gas emissions, energy consumption and energy efficiency

Disclosures in relation to greenhouse gas emissions, energy consumption and energy efficiency are included in Sustainability – on page 50.

Disclosures required under Listing Rule 9.8.4R

The information required to be disclosed by Listing Rule 9.8.4R can be located as set out below:

Information required	Page
(1) Amount of interest capitalized	183
(2) – (4)	Not applicable
(5), (6) Waiver of director emoluments	121
(7) – (11)	Not applicable
(12), (13) Dividend waivers	328
(14)	Not applicable

★ See Glossary

Cautionary statement

In order to utilize the 'safe harbor' provisions of the United States Private Securities Litigation Reform Act of 1995 (the 'PSLRA') and the general doctrine of cautionary statements, bp is providing the following cautionary statement.

This document contains certain forecasts, projections and forward-looking statements - that is, statements related to future, not past, events and ircumstances - with respect to the financial condition, results of operations and businesses of bp and certain of the plans and objectives of bp with respect to these items. These statements may generally, but not always, be identified by the use of words such as 'will', 'expects', 'is expected to', 'aims', 'should', 'may', 'objective', 'is likely to', 'intends', 'believes', 'anticipates', 'plans', 'we see' or similar expressions. In particular, among other statements, (i) certain statements in the Chairman's letter (pages 4-5), the Group chief executive's letter (pages 6-7), the Strategic report (inside cover and pages 1-70), Additional disclosures (pages 301-330) and Shareholder information (pages 331-340), including but not limited to statements under the headings 'Our Energy Outlook', 'Reinventing bp – our business model', 'Reinventing bp – our strategic focus areas', 'Reinventing bp – our financial frame', '2021 guidance' and 'Reinventing bp – in line with the Paris goals' and including but not limited to statements regarding: plans and expectations relating to operating cash flow, capital expenditure (including total capital expenditure, organic capital expenditure and inorganic capital expenditure), maintaining a strong financial frame, deleveraging bp's balance sheet, working capital and operating cash flows, liquidity, capital discipline, future sustainable free cash flow and shareholder distributions, allocation of capital to bp's energy transition strategy, amount or timing of payments related to divestment proceeds, net debt, gearing and future dividend payments and share buybacks; bp's ambition to be a net zero company by 2050 or sooner, including its aims regarding Scope 1, Scope 2 and Scope 3 emissions, its expectations for the energy transition and the carbon content of its oil and gas production, while operating a high-quality base business; bp's plan to amplify value by focusing on integrating energy systems, partnering with countries, cities and industries, and driving digital innovation; expectations regarding medium and long-term oil prices, the consistency of pricing assumptions with scenarios that are consistent with the Paris goals and bp's resilience to Paris-consistent pathways; expectations regarding world energy demand, including the growth in relative demand for renewables, oil and gas, and the proportional growth of renewables; expectations regarding bp's short, medium- and long-term targets and aims for emissions and carbon intensity of bp's production and marketed products, and statements regarding the resilience of bp's strategy and portfolio across multiple climate scenarios and the uncertainties in the energy transition; plans and expectations regarding bp's level of investment in energy sources and technologies other than oil and gas resources and reserves, including plans to increase investment in low carbon from around $750 million in 2020 to $3-4 billion by 2025 and to around $5 billion a year in 2030, with transition capital spend to be as much as 50% of capex in 2030; plans and expectations to significantly increase bp's investment in low carbon activities in this decade, while also operating a high-quality base business; plans and expectations regarding bp's five aims to get bp to net zero, including the aim to be net zero across its entire operations on an absolute basis by 2050 or sooner, the aim to be net zero on an absolute basis across the carbon in its upstream oil and gas production by 2050 or sooner, the aim to cut the carbon intensity of products sold by 50% by 2050 or sooner, the aim to install methane measurement at all existing major oil and gas processing sites by 2023, publish the data, and then drive a 50% reduction in methane intensity of operations, and the aim to increase the proportion of investment bp makes into its non-oil and gas businesses; plans and expectations regarding bp's five aims to get the world to net zero carbon emissions, including the aim to more actively advocate for policies that support net zero, including carbon pricing, the aim to incentivize bp's global workforce to deliver on these aims and mobilize them to become advocates for net zero, the aim to set new expectations for relationships with trade associations around the globe, the aim to be recognized as an industry leader for the transparency of its reporting and the aim to launch a new team to create integrated clean energy and mobility solutions; expectations with respect to oil and gas supply and demand and prices; expectations with respect to the world energy mix, production, consumption and emissions; plans and expectations with respect to low carbon spend in 2021; expectations with respect to transition capital, and the percentage of capital expenditure that will be low-carbon; expectations that the aftermath of the pandemic will accelerate the pace of transition to a lower carbon economy and energy system; expectations that the Empire Wind project in New York state will have 2GW generating capacity once operational and Beacon Wind will have 2.4GW generating capacity once operational; expectations regarding future legislative or regulatory action related to greenhouse gases, including emissions disclosure, emissions trading, and fuel-specific regulations, and their impact on bp; expectations regarding pensions and other post-retirement benefits, including contributions; expectations regarding payments under contractual obligations and sales commitments; expectations that around 10,000 employees will leave bp by early 2022; plans and expectations regarding bp's workforce, including bp's targets regarding diversity, inclusion and equality; expectations regarding bp's ability to prevent violations of its code of conduct, including its anti-bribery and corruption policies and procedures; plans and expectations regarding the new leadership structure and governance framework, including areas of focus and effectiveness; plans for incentivising bp's global workforce; policies and goals related to risk management plans; plans and expectations regarding control deficiencies; expectations regarding bp's ability to prevent, respond to and recover from cyberattacks or hostile actions; plans and projections regarding oil and gas reserves, including the turnover time of proved undeveloped reserves to proved developed reserves and volume of turnover; expectations regarding the costs of environmental restoration, remediation and abatement programmes; plans and expectations regarding bp's portfolio, including to maintain a focused portfolio, to manage the portfolio through disciplined investment to support growing returns and to focus on highest-quality barrels; expectations that by 2030 bp's hydrocarbon production will be around 40% lower relative to 2019 due to active management and high-grading of the portfolio, including divestment of non-core assets; plans and expectations that bp will not undertake exploration activity in new countries; expectations regarding contingent liabilities and their impact on bp; expectations regarding the future value of assets; expectations with respect to reserves bookings from new discoveries; plans and expectations with regard to the supply and trading function, the fuels and the lubricants businesses; plans and expectations with regard to new technologies, including their efficiency and impact on production; plans and expectations regarding sales commitments of bp and its equity-accounted entities; expectations regarding underlying production and capital investment; expectations with respect to ROACE and earnings before interest, tax, depreciation and amortisation; plans and expectations regarding investment, development, and production levels and the timing thereof with respect to projects and partnerships in Angola, Australia, Azerbaijan, Brazil, Egypt, the Gambia, India, Indonesia, Mexico, Russia, São Tomé and Príncipe, Turkey, Oman, the UK North Sea, the Gulf of Mexico, and the continental United States; expectations regarding refining margins; plans to undertake joint exploration and development with Rosneft and plans and expectations for the Strategic Collaboration Agreement signed between Rosneft and bp; expectations regarding future government action, regulations and policy, their impact on bp's business and plans regarding compliance with such regulations; expectations regarding legal and trial proceedings, court decisions, potential investigations and civil actions by regulators, government entities and/ or other entities or parties, and the timing and potential impact of such proceedings and bp's intentions in respect thereof; plans and expectations regarding relationships with governments, customers, partners, suppliers, communities and key stakeholders; plans to produce 900,000boe/d from new projects by 2021 and expectations regarding operating cash margins of this production; plans and expectations for bp's Jio-bp joint venture with Reliance, including the expectation for 5,500 Jio-bp retail sites by 2025; plans and expectations to deliver 2021 financial targets; plans to increase investment in low carbon to $3-4 billion by 2025 and to around $5 billion a year in 2030; expectations related to delivery and execution of Atlantis Phase 3 in the US Gulf of Mexico; expectations regarding customer touchpoints, number of strategic convenience sites, number of retail sites in growth markets, Castrol sales and other operating revenues, number of electric vehicle charge points, margin share from convenience and electrification, unit production costs, Upstream production, Upstream plant reliability, refining throughout, refining availability, developed renewables to final investment decision, bioenergy production, LNG portfolio, and traded electricity;

expectations regarding oil prices, including for long-term prices to be affected by the enduring impact of the COVID-19 pandemic, the decisions of OPEC+, confidence in efforts to manage the rollout of vaccination and further virus control measures; expectations regarding Upstream reported production excluding Rosneft , total capital expenditure, depreciation, depletion and amortisation charges, Gulf of Mexico oil spill payments (post-tax), the Other business and corporate annual charge and underlying quarterly charge, and the effective tax rate and the underlying effective tax rate; plans and expectations regarding the effectiveness of the group's foreign currency exchange risk management; expectations regarding bp's partnership with Equinor for offshore wind in the US, including bp's expectation of pursuing further opportunities for offshore wind in the US, and regarding bp's partnership with Ørsted on an industrial-scale project to produce hydrogen from water, powered by wind; expectations regarding the US gas market in 2021 as supply declines and demand for LNG exports recovers and that the current tightness on global LNG markets and higher US gas prices will lift other regional gas prices; expectations for limited growth in oil supply from non-OPEC+ countries coupled with active market management from OPEC+ leading to normalization of the currently high inventory levels, with prices subject to the decisions of OPEC+; expectations that US gas markets are likely to benefit from lower production and a recovery in international LNG demand driven by demand in Asia; expectations that demand for refined products will remain strong over the remaining useful life of existing assets; expectations that the majority of bp's Upstream oil and gas properties will start decommissioning within the next two decades; expectations that the majority of bp's reserves and resources that support the carrying value of the group's existing oil and gas properties are expected to be produced over the next 10 years; expectations that reported production will be lower due to the impact of the ongoing divestment programme; expectations regarding level and volatility of other businesses and corporate charges for 2021; plans and expectations regarding bp's in-scope projects' impact on biodiversity; expectation's regarding bp's impact on air emissions and water use and management; expectations regarding fulfillment of existing delivery commitments for oil and gas; expectations regarding Gulf of Mexico oil spill payments; expectations that first oil from the Thunder Horse South Expansion will be reached in the third quarter of 2021 and that first oil for the Mad Dog 2 project will be reached in the second quarter of 2022; expectations that the Cassia Compression project will start up in 2022; expectations that first production from the Total-operated Zinia 2 deep offshore development project will occur in 2021; expectation that first production from the Platina project will occur in 2021; expectation for start-up of the West Nile Delta Raven project in the first quarter of 2021; expectations that the Tangguh expansion project will start-up in 2022; and plans and expectations regarding bp Ventures and Launchpad; and (ii) certain statements in Corporate governance (pages 71-102) and the Directors' remuneration report (pages 103-126) with regard to: the anticipated future composition of the board of directors and the effects thereof; the board's goals and areas of focus, including changes to KPIs and those goals stemming from the board's annual evaluation; plans and expectations regarding directors' share ownership and remuneration; plans regarding the governance and remuneration processes; and goals, activities and areas of focus of board committees, are all forward looking in nature. By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of bp. Actual results may differ materially from those expressed in such statements, depending on a variety of factors, including: the specific factors identified in the discussions accompanying such forward looking statements; the effects of the COVID-19 pandemic and uncertainties about its impact and duration; the receipt of relevant third party and/or regulatory approvals; the timing and level of maintenance and/or turnaround activity; the timing and volume of refinery additions and outages; the timing of bringing new projects onstream; the timing, quantum and nature of certain acquisitions and divestments; future levels of industry product supply, demand and pricing, including supply growth in North America; OPEC+ quota restrictions; production-sharing agreements effects; operational and safety problems; potential lapses in product quality; economic and financial market conditions generally or in various countries and regions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations and policies, including related to climate change; changes in social attitudes and customer preferences; regulatory or legal actions including the types of enforcement action pursued and the nature of remedies sought or imposed; the actions of prosecutors, regulatory authorities and courts; delays in the processes for resolving claims; amounts ultimately determined to be payable and the timing of payments relating to the Gulf of Mexico oil spill; exchange rate fluctuations; development and use of new technology; recruitment and retention of a skilled workforce; the success or otherwise of partnering; the actions of competitors, trading partners, contractors, subcontractors, creditors, rating agencies and others; bp's access to future credit resources; business disruption and crisis management; the impact on bp's reputation of ethical misconduct and noncompliance with regulatory obligations; trading losses; major uninsured losses; decisions by Rosneft's management and board of directors; the actions of contractors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; public health situations (including an outbreak of an epidemic or pandemic); wars and acts of terrorism; cyberattacks or sabotage; and other factors discussed elsewhere in this report including under Risk factors (pages 67-70). In addition to factors set forth elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Statements regarding competitive position

Statements referring to bp's competitive position are based on the company's belief and, in some cases, rely on a range of sources, including investment analysts' reports, independent market studies and bp's internal assessments of market share based on publicly available information about the financial results and performance of market participants.

Shareholder information

Share prices and listings

Markets and market prices

The primary market for the company's ordinary shares (trading symbol 'BP.'), 8% cumulative first preference shares (trading symbol 'BP.A') and 9% cumulative second preference shares (trading symbol 'BP.B') is the London Stock Exchange (LSE). The company's ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index.

In the US, the company's securities are listed and traded on the New York Stock Exchange (NYSE) in the form of ADSs (trading symbol 'BP'), for which JPMorgan Chase Bank, N.A. is the depositary (the Depositary) and transfer agent. The Depositary's principal office is 383 Madison Avenue, Floor 11, New York, NY, 10179, US. Each ADS represents six ordinary shares. ADSs are evidenced by American depositary receipts (ADRs), which may be issued in either certificated or book entry form.

The company's ordinary shares are also traded in the form of a global depositary certificate representing the company's ordinary shares on the Frankfurt, Hamburg and Dusseldorf Stock Exchanges.

On 25 February 2021, 849,802,947 ADSs (equivalent to approximately 5,098,817,682 ordinary shares or some 25.06% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 72,535 ADS holders. Of these, about 71,703 had registered addresses in the US at that date. One of the registered holders of ADSs represents approximately 1,087,342 underlying holders.

On 25 February 2021, there were approximately 225,319 ordinary shareholders. Of these shareholders, around 1,539 had registered addresses in the US and held a total of some 4,381,925 ordinary shares.

Since a number of the ordinary shares and ADSs were held by brokers and other nominees, the number of holders in the US may not be representative of the number of beneficial holders or their respective country of residence.

Dividends

The company's current policy is to pay interim dividends on a quarterly basis on its ordinary shares.

Its policy is also to announce dividends for ordinary shares in US dollars and state an equivalent sterling dividend. Dividends on the company's ordinary shares will be paid in sterling and on the company's ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the market exchange rates in London over the four business days prior to the sterling equivalent announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced. It is not the company's intention to change its current policy of announcing dividends on ordinary shares in US dollars.

Information regarding dividends announced and paid by the company on ordinary shares and preference shares is provided in Financial statements – Note 10.

A Scrip Dividend Programme (Scrip Programme) was approved by shareholders in 2010 and was renewed for a further three years at the 2018 AGM. It is proposed that the Scrip Programme be renewed for a further three years at the 2021 AGM. It enabled the company's ordinary shareholders and ADS holders to elect to receive dividends by way of new fully paid ordinary shares (or ADSs in the case of ADS holders) instead of cash. The operation of the Scrip Programme is always subject to the directors' decision to make the Scrip Programme offer available in respect of any particular dividend.

The company announced on 29 October 2019 and as part of all subsequent quarterly results announcements made since that the board had suspended the Scrip Programme in respect of those quarterly dividends. Ordinary shareholders and ADS holders (subject to certain exceptions) may be able to participate in dividend reinvestment plans. Any decisions with respect to future dividends will be made by the board of BP p.l.c. following the end of each quarter.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on page 67 and other matters that may affect the business of the group set out in Our strategy on page 15 and in Liquidity and capital resources on page 306.

The following table shows dividends announced and paid by the company per ADS for the past five years.

Dividends per ADS[a]		March	June	September	December	Total
2016	UK pence	42.08	41.50	45.35	47.59	176.52
	US cents	60	60	60	60	240
2017	UK pence	48.95	46.54	45.73	44.66	185.88
	US cents	60	60	60	60	240
2018	UK pence	43.01	44.66	47.58	48.15	183.40
	US cents	60	60	61.50	61.50	243
2019	UK pence	46.43	48.39	50.09	46.95	191.86
	US cents	61.50	61.50	61.50	61.50	246
2020	**UK pence**	**48.94**	**50.05**	**24.26**	**23.50**	**146.75**
	US cents	**63.00**	**63.00**	**31.50**	**31.50**	**189**

[a] Dividends announced and paid by the company on ordinary and preference shares are provided in Financial statements – Note 10.

There are currently no UK foreign exchange controls or restrictions on remittances of dividends on the ordinary shares or on the conduct of the company's operations, other than restrictions applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

Shareholder taxation information

This section describes the material US federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder who holds the ordinary shares or ADSs as capital assets for tax purposes. It does not apply, however, inter alia to members of special classes of holders some of which may be subject to other rules, including: tax-exempt entities, life insurance companies, dealers in securities, traders in securities that elect a mark-to-market method of accounting for securities holdings, investors liable for alternative minimum tax, holders that, directly or indirectly, hold 10% or more of the company's shares (as measured by voting power or value), holders that hold the shares or ADSs as part of a straddle or a hedging or conversion transaction, holders that purchase or sell the shares or ADSs as part of a wash sale for US federal income tax purposes, or holders whose functional currency is not the US dollar. In addition, if a partnership holds the shares or ADSs, the US federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership and may not be described fully below.

A US holder is any beneficial owner of ordinary shares or ADSs that is for US federal income tax purposes (1) a citizen or resident of the US, (2) a US domestic corporation, (3) an estate whose income is subject to US federal income taxation regardless of its source, or (4) a trust if a US court can exercise primary supervision over the trust's administration and one or more US persons are authorized to control all substantial decisions of the trust.

This section is based on the tax laws of the United States, including the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed US Treasury regulations thereunder, published rulings and court decisions, and the taxation laws of the UK, all as currently in effect, as well as the income tax convention between the US and the UK that entered into force on 31 March 2003 (the 'Treaty'). These laws are subject to change, possibly on a retroactive basis. This section further assumes that each obligation under the terms of the deposit agreement relating to bp ADSs and any related agreement will be performed in accordance with its terms.

For purposes of the Treaty and the estate and gift tax Convention (the 'Estate Tax Convention') and for US federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the company's ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs and ADRs for ordinary shares generally will not be subject to US federal income tax or to UK taxation other than stamp duty or stamp duty reserve tax, as described below.

Investors should consult their own tax adviser regarding the US federal, state and local, UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Treaty in respect of their investment in the shares or ADSs.

Taxation of dividends

UK taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the company, including dividends paid to US holders. A shareholder that is a company resident for tax purposes in the UK or trading in the UK through a permanent establishment generally will not be taxable in the UK on a dividend it receives from the company. A shareholder who is an individual resident for tax purposes in the UK is subject to UK tax on dividends received from the company, including dividends received under the dividend reinvestment plan (DRIP) for ordinary shareholders, but until 5 April 2016, was entitled to a tax credit on cash dividends paid on ordinary shares or ADSs of the company equal to one-ninth of the cash dividend.

From 6 April 2016 the dividend tax credit was replaced by a new tax-free dividend allowance and dividends paid by the company on or after 6 April 2016 do not carry a UK tax credit. The dividend allowance was £5,000 but this has been reduced to £2,000 as of 6 April 2018.

The dividend allowance of £2,000 means there is no UK tax due on the first £2,000 of dividends received. Dividends above this level are subject to tax at 7.5% for basic tax payers, 32.5% for higher rate tax payers and 38.1% for additional rate tax payers.

Although the first £2,000 of dividend income is not subject to UK income tax, it does not reduce the total income for tax purposes. Dividends within the dividend allowance still count towards basic or higher rate bands, and may therefore affect the rate of tax paid on dividends received in excess of the £2,000 allowance. For instance, if an individual has an annual gross salary of £50,000 and also receives a dividend of £12,000 they will be subject to the following scenario. The individual's personal allowance and the basic rate tax band will be used up by the gross salary. The remaining part of the salary and the whole of the dividend will be subject to tax at the higher rate, although the dividend allowance will reduce the amount of dividend subject to tax. The dividend of £12,000 will be reduced by the dividend allowance of £2,000 leaving taxable dividend income of £10,000. The dividend will be taxed at 32.5% so that the total tax payable on the dividends is £3,250.

How the shareholder pays the tax arising on the dividend income depends on the amount of dividend income and salary they receive in the tax year. If less than £2,000 they will not need to report anything or pay any tax. If between £2,000 and £10,000, the shareholder can pay what they owe by: contacting the helpline; asking HMRC to change their tax code – the tax will be taken from their wages or pension or through completion of the 'Dividends' section of their tax return, where one is being filed. If over £10,000 they will be required to file a self-assessment tax return and should complete the 'Dividends' section with details of the amounts received.

US federal income taxation

A US holder is subject to US federal income taxation on the gross amount of any dividend paid by the company (including dividends paid but reinvested received under the Global Invest Direct (GID) Dividend Reinvestment Plan for ADS holders) out of its current or accumulated earnings and profits (as determined for US federal income tax purposes). Dividends paid to a non-corporate US holder that constitute qualified dividend income will be taxable to the holder at a preferential rate, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the company with respect to the ordinary shares or ADSs will generally be qualified dividend income.

For US federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depositary, in the case of ADSs, actually or constructively receives the dividend and will not be eligible for the dividends-received deduction generally allowed to US corporations in respect of dividends received from other US corporations. US ADS holders should consult their own tax adviser regarding the US tax treatment of the dividend fee in respect of dividends. Dividends will be income from sources outside the US and generally will be 'passive category income' or, in the case of certain US holders, 'general category income', each of which is treated separately for purposes of computing a US holder's foreign tax credit limitation.

As noted above in UK taxation, a US holder will not be subject to UK withholding tax. Accordingly, the receipt of a dividend will not entitle the US holder to a foreign tax credit.

The amount of the dividend distribution on the ordinary shares that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/US dollar rate on the date the dividend distribution is includible in income, regardless of whether the payment is, in fact, converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is includible in income to the date the payment is converted into US dollars will be treated as ordinary income or loss and will not be eligible for the preferential tax rate on qualified dividend income. The gain or loss generally will be income or loss from sources within the US for foreign tax credit limitation purposes.

Distributions in excess of the company's earnings and profits, as determined for US federal income tax purposes, will be treated as a return of capital to the extent of the US holder's basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described in Taxation of capital gains – US federal income taxation section below.

In addition, the taxation of dividends may be subject to the rules for passive foreign investment companies (PFIC), described below under 'Taxation of capital gains – US federal income taxation'. Distributions made by a PFIC do not constitute qualified dividend income and are not eligible for the preferential tax rate applicable to such income.

Taxation of capital gains

UK taxation

A US holder may be liable for both UK and US tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (1) resident for tax purposes in the United Kingdom at the date of disposal, (2) if he or she has left the UK for a period not exceeding five complete tax years between the year of departure from and the year of return to the UK and acquired the shares before leaving the UK and was resident in the UK in the previous four out of seven tax years before the year of departure, (3) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK or (4) a citizen of the US that carries on a trade or profession or vocation in the UK through a branch or agency or a corporation that carries on a trade, profession or vocation in the UK, through a permanent establishment, and that has used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment. However, such persons may be entitled to a tax credit against their US federal income tax liability for the amount of UK capital gains tax or UK corporation tax on chargeable gains (as the case may be) that is paid in respect of such gain.

Under the Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence of the relevant holder as determined under both the laws of the UK and the US and as required by the terms of the Treaty.

Under the Treaty, individuals who are residents of either the UK or the US and who have been residents of the other jurisdiction (the US or the UK, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the company not only in the jurisdiction of which the holder is resident at the time of the disposition but also in the other jurisdiction.

For gains on or after 23 June 2010, the UK Capital Gains Tax rate will be dependent on the level of an individual's taxable income. Where total taxable income and gains after all allowable deductions are less than the upper limit of the basic rate income tax band of £37,500 (for 2020/21), the rate of Capital Gains Tax will be 10%. For gains (and any parts of gains) above that limit the rate will be 20%.

From 6 April 2008, entitlement to the annual exemption is based on an individual's circumstances (taking into account Domicile status, remittance basis of taxation and number of years in the UK). For individuals who are entitled to the exemption for 2020/21, this has been set at £12,300. Corporation tax on chargeable gains is levied at 19 per cent for companies from 1 April 2017.

US federal income taxation

A US holder who sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for US federal income tax purposes equal to the difference between the US dollar value of the amount realized on the disposition and the US holder's tax basis, determined in US dollars, in the ordinary shares or ADSs. Any such capital gain or loss generally will be long-term gain or loss, subject to tax at a preferential rate for a non-corporate US holder, if the US holder's holding period for such ordinary shares or ADSs exceeds one year. The tax basis of shares acquired through reinvested dividends under the GID Dividend Reinvestment Plan for ADS holders) is equal to the fair market value of the stock on the investment date. The holding period for shares acquired under the plan begins the day after the applicable investment date.

Gain or loss from the sale or other disposition of ordinary shares or ADSs will generally be income or loss from sources within the US for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

We do not believe that ordinary shares or ADSs will be treated as stock of a passive foreign investment company (PFIC) for US federal income tax purposes, but this conclusion is a factual determination that is made annually and thus is subject to change. If we are treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to ordinary shares or ADSs, any gain realized on the sale or other disposition of ordinary shares or ADSs would in general not be treated as capital gain. Instead, a US holder would be treated as if he or she had realized such gain rateably over the holding period for ordinary shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, in addition to which an interest charge in respect of the tax attributable to each such year would apply. Certain 'excess distributions' would be similarly treated if we were treated as a PFIC.

Additional tax considerations

Scrip Programme

Until the publication of the 2019 third quarter results, the company had an optional Scrip Programme, wherein holders of bp ordinary shares or ADSs could elect to receive any dividends in the form of new fully paid ordinary shares or ADSs of the company instead of cash. Please consult your tax adviser for the consequences to you.

UK inheritance tax

The Estate Tax Convention applies to inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to UK inheritance tax on the individual's death or on transfer during the individual's lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK used for the performance of independent personal services. In the exceptional case where ADSs are subject to both inheritance tax and US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

UK stamp duty and stamp duty reserve tax

The statements below relate to what is understood to be the current practice of HM Revenue & Customs in the UK under existing law.

Provided that any instrument of transfer is not executed in the UK and remains at all times outside the UK and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of £5 per £1,000 (or part, unless the stamp duty is less than £5, when no stamp duty is charged), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser.

A subsequent transfer of ordinary shares to the Depositary's nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer. For ADR holders electing to receive ADSs instead of cash, after the 2012 first quarter dividend payment, HM Revenue & Customs no longer seeks to impose 1.5% stamp duty reserve tax on issues of UK shares and securities to non-EU clearance services and depositary receipt systems.

Major shareholders

The disclosure of certain major and significant shareholdings in the share capital of the company is governed by the Companies Act 2006, the UK Financial Conduct Authority's Disclosure Guidance and Transparency Rules (DTR) and the US Securities Exchange Act of 1934.

Register of members holding bp ordinary shares as at 31 December 2020

Range of holdings	Number of ordinary shareholders	Percentage of total ordinary shareholders	Percentage of total ordinary share capital excluding shares held in treasury
1-200	52,385	23.06	0.01
201-1,000	75,742	33.35	0.21
1,001-10,000	86,759	38.20	1.36
10,001-100,000	10,733	4.73	1.10
100,001-1,000,000	824	0.36	1.45
Over 1,000,000[a]	674	0.30	95.87
Totals	227,117	100.00	100.00

[a] Includes JPMorgan Chase Bank, N.A. holding 25.33% of the total ordinary issued share capital (excluding shares held in treasury) as the approved depositary for ADSs, a breakdown of which is shown in the table below.

Register of holders of American depositary shares (ADSs) as at 31 December 2020[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	43,236	59.04	0.27
201-1,000	19,362	26.44	1.07
1,001-10,000	10,198	13.92	3.06
10,001-100,000	432	0.59	0.82
100,001-1,000,000	7	0.01	0.22
Over 1,000,000[b]	1	0.00	94.56
Totals	73,236	100.00	100.00

[a] One ADS represents six 25 cent ordinary shares.

[b] One holder of ADSs represents 1,056,393 approx. underlying shareholders.

As at 31 December 2020 there were also 1,212 preference shareholders. Preference shareholders represented 0.42% and ordinary shareholders represented 99.58% of the total issued nominal share capital of the company (excluding shares held in treasury) as at that date.

As at 31 December 2020, the company had not received any notifications pursuant to DTR5. The company also did not receive any notifications pursuant to DTR5 between 1 January 2021 and 25 February 2021.

Under the US Securities Exchange Act of 1934 bp is aware of the following interests as at 25 February 2021:

Holder	Holding of ordinary shares	Percentage of ordinary share capital excluding shares held in treasury
JPMorgan Chase Bank N.A., depositary for ADSs, through its nominee Guaranty Nominees Limited	5,098,817,683	25.06
BlackRock, Inc.	1,514,099,140	7.69
The Vanguard Group, Inc	763,396,544	3.75

The company's major shareholders do not have different voting rights.

The company has also been notified of the following interests in preference shares as at 25 February 2021:

Holder	Holding of 8% cumulative first preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society Limited	945,000	13.07
Hargreaves Lansdown Asset Management Limited	698,778	9.66
Interactive Investor Share Dealing Services	573,177	7.92
M & G Investment Management Ltd.	528,150	7.30
Canaccord Genuity Group Inc.	504,162	6.97
Halifax Share Dealing Services	416,661	5.76

Holder	Holding of 9% cumulative second preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society Limited	987,000	18.03
M & G Investment Management Ltd.	644,450	11.77
Safra Group	385,000	7.03
Canaccord Genuity Group Inc.	306,605	5.60

As at 25 February 2021, the total preference shares in issue comprised only 0.42% of the company's total issued nominal share capital (excluding shares held in treasury), the rest being ordinary shares.

Annual general meeting

The 2021 AGM is scheduled to be held on Wednesday 12 May 2021 at 11.00am. A separate notice convening the meeting is distributed to shareholders, which includes an explanation of the items of business to be considered at the meeting.

All resolutions for which notice has been given will be decided on a poll. Deloitte LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in the *Notice of bp Annual General Meeting 2021*.

Memorandum and Articles of Association

The following summarizes certain provisions of the company's Memorandum and Articles of Association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act 2006 (the Act) and the company's Memorandum and Articles of Association. The Memorandum and Articles of Association are available online at *bp.com/usefuldocs*.

The company's Articles of Association may be amended by a special resolution at a general meeting of the shareholders. At the annual general meeting (AGM) held on 21 May 2018 shareholders voted to adopt new Articles of Association to reflect developments in market practice and to provide clarification and additional flexibility where necessary or appropriate.

Objects and purposes

bp is a public company limited by shares, incorporated under the name BP p.l.c. and is registered in England and Wales with the registered number 102498. The provisions regulating the operations of the company, known as its 'objects', were historically stated in a company's memorandum. The Act abolished the need to have object provisions and so at the AGM held on 15 April 2010 shareholders approved the removal of its objects clause together with all other provisions of its Memorandum that, by virtue of the Act, are treated as forming part of the company's Articles of Association.

Directors and secretary

The business and affairs of bp shall be managed by the directors. The company's Articles of Association provide that directors may be appointed by the existing directors or by the shareholders in a general meeting. Any person appointed by the directors will hold office only until the next general meeting, notice of which is first given after their appointment and will then be eligible for re-election by the shareholders. A director may be removed by bp as provided for by applicable law and shall vacate office in certain circumstances as set out in the Articles of Association. In addition the company may, by special resolution, remove a director before the expiration of his/her period of office and, subject to the Articles of Association, may by ordinary resolution appoint another person to be a director instead. There is no requirement for a director to retire on reaching any age.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which the director has a material interest other than by virtue of such director's interest in shares in the company. However, in the absence of some other material interest not indicated below, a director is entitled to vote and to be counted in a quorum for the purpose of any vote relating to a resolution concerning the following matters:

- The giving of security or indemnity with respect to any money lent or obligation taken by the director at the request or benefit of the company or any of its subsidiary undertakings.
- Any proposal in which the director is interested, concerning the underwriting of company securities or debentures or the giving of any security to a third party for a debt or obligation of the company or any of its subsidiary undertakings.
- Any proposal concerning any other company in which the director is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that the director and persons connected with such director are not the holder or holders of 1% or more of the voting interest in the shares of such company.
- Any proposal concerning the purchase or maintenance of any insurance policy under which the director may benefit.
- Any proposal concerning the giving to the director of any other indemnity which is on substantially the same terms as indemnities given or to be given to all of the other directors or to the funding by the company of his expenditure on defending proceedings or the doing by the company of anything to enable the director to avoid incurring such expenditure where all other directors have been given or are to be given substantially the same arrangements.
- Any proposal concerning an arrangement for the benefit of the employees and directors or former employees and former directors of the company or any of its subsidiary undertakings, including but without being limited to a retirement benefits scheme and an employees' share scheme, which does not accord to any director any privilege or advantage not generally accorded to the employees or former employees to whom the arrangement relates.

The Act requires a director of a company who is in any way interested in a contract or proposed contract with the company to declare the nature of the director's interest at a meeting of the directors of the company. The definition of 'interest' includes the interests of spouses, children, companies and trusts. The Act also requires that a director must avoid a situation where a director has, or could have, a direct or indirect interest that conflicts, or possibly may conflict, with the company's interests. The Act allows directors of public companies to authorize such conflicts where appropriate, if a company's Articles of Association so permit. bp's Articles of Association permit the authorization of such conflicts. The directors may exercise all the powers of the company to borrow money, except that the amount remaining undischarged of all moneys borrowed by the company shall not, without approval of the shareholders, exceed two times the amount paid up on the share capital plus the aggregate of the amount of the capital and revenue reserves of the company. Variation of the borrowing power of the board may only be affected by amending the Articles of Association.

Remuneration of non-executive directors shall be determined in the aggregate by resolution of the shareholders. Remuneration of executive directors is determined by the remuneration committee. This committee is made up of non-executive directors only. There is no requirement of share ownership for a director's qualification.

The Articles of Association provide entitlement to the directors' pensions and death and disability benefits to the directors' relations and dependants respectively.

The circumstances in which a director's office will automatically terminate include: when a director ceases to hold an executive office of the company and the directors resolve that he should cease to be a director; if a medical practitioner provides an opinion that a director has become incapable of acting as a director and may remain so incapable for a further three months and the directors resolve that he should cease to be a director; and if all of the other directors vote in favour of a resolution stating that the person should cease to be a director.

The company secretary has express powers to delegate any of the powers or discretions conferred on him or her.

Dividend rights; other rights to share in company profits; capital calls

If recommended by the directors of bp, shareholders of bp may, by resolution, declare dividends but no such dividend may be declared in excess of the amount recommended by the directors. The directors may also pay interim dividends without obtaining shareholder approval. No dividend may be paid other than out of profits available for distribution, as determined under IFRS and the Act. Dividends on ordinary shares are payable only after payment of dividends on bp preference shares. Any dividend unclaimed after a period of 10 years from the date of declaration of such dividend shall be forfeited and reverts to bp. If the company exercises its right to forfeit shares and sells shares belonging to an untraced shareholder then any entitlement to claim dividends or other monies unclaimed in respect of those shares will be for a period of twelve months after the sale. The company may take such steps as the directors decide are appropriate in the circumstances to trace the member entitled and the sale may be made at such time and on such terms as the directors may decide.

The directors have the power to declare and pay dividends in any currency provided that a sterling equivalent is announced. It is not the company's intention to change its current policy of paying dividends in US dollars. At the company's AGM held on 15 April 2010, shareholders approved the introduction of a Scrip Dividend Programme (Scrip Programme) and to include provisions in the Articles of Association to enable the company to operate the Scrip Programme. The Scrip Programme was renewed at the company's AGM held on 21 May 2018 for a further three years. The Scrip Programme enables ordinary shareholders and bp ADS holders to elect to receive new fully paid ordinary shares (or bp ADSs in the case of bp ADS holders) instead of cash. The operation of the Scrip Programme is always subject to the directors' decision to make the scrip offer available in respect of any particular dividend. Should the directors decide not to offer the scrip in respect of any particular dividend, cash will automatically be paid instead. The directors may determine in relation to any scrip dividend plan or programme how the costs of the programme will be met, the minimum number of ordinary shares required in order to be able to participate in the programme and any arrangements to deal with legal and practical difficulties in any particular territory.

Apart from shareholders' rights to share in bp's profits by dividend (if any is declared or announced), the Articles of Association provide that the directors may set aside:

- A special reserve fund out of the balance of profits each year to make up any deficit of cumulative dividend on the bp preference shares.
- A general reserve out of the balance of profits each year, which shall be applicable for any purpose to which the profits of the company may properly be applied. This may include capitalization of such sum, pursuant to an ordinary shareholders' resolution, and distribution to shareholders as if it were distributed by way of a dividend on the ordinary shares or in paying up in full unissued ordinary shares for allotment and distribution as bonus shares.

Any such sums so deposited may be distributed in accordance with the manner of distribution of dividends as described above.

Holders of shares are not subject to calls on capital by the company, provided that the amounts required to be paid on issue have been paid off. All shares are fully paid.

Share transfers and share certificates

The directors may permit transfers to be effected other than by an instrument in writing and that share certificates will not be required to be issued by the company if they are not required by law.

The company may charge an administrative fee in the event that a shareholder wishes to replace two or more certificates representing shares with a single certificate or wishes to surrender a single certificate and replace it with two or more certificates. All certificates are sent at the member's risk.

Voting rights

The Articles of Association of the company provide that voting on resolutions at a shareholders' meeting will be decided on a poll other than resolutions of a procedural nature, which may be decided on a show of hands. If voting is on a poll, every shareholder who is present in person or by proxy has one vote for every ordinary share held and two votes for every £5 in nominal amount of bp preference shares held. If voting is on a show of hands, each shareholder who is present at the meeting in person or whose duly appointed proxy is present in person will have one vote, regardless of the number of shares held, unless a poll is requested.

Shareholders do not have cumulative voting rights.

For the purposes of determining which persons are entitled to attend or vote at a shareholders' meeting and how many votes such persons may cast, the company may specify in the notice of the meeting a time, not more than 48 hours before the time of the meeting, by which a person who holds shares in registered form must be entered on the company's register of members in order to have the right to attend or vote at the meeting or to appoint a proxy to do so.

Holders on record of ordinary shares may appoint a proxy, including a beneficial owner of those shares, to attend, speak and vote on their behalf at any shareholders' meeting, provided that a duly completed proxy form is received not less than 48 hours (or such shorter time as the directors may determine) before the time of the meeting or adjourned meeting or, where the poll is to be taken after the date of the meeting, not less than 24 hours (or such shorter time as the directors may determine) before the time of the poll.

Record holders of bp ADSs are also entitled to attend, speak and vote at any shareholders' meeting of bp by the appointment by the approved depositary, JPMorgan Chase Bank N.A., of them as proxies in respect of the ordinary shares represented by their ADSs. Each such proxy may also appoint a proxy. Alternatively, holders of bp ADSs are entitled to vote by supplying their voting instructions to the depositary, who will vote the ordinary shares represented by their ADSs in accordance with their instructions.

Proxies may be delivered electronically.

Corporations who are members of the company may appoint one or more persons to act as their representative or representatives at any shareholders' meeting provided that the company may require a corporate representative to produce a certified copy of the resolution appointing them before they are permitted to exercise their powers.

Matters are transacted at shareholders' meetings by the proposing and passing of resolutions, of which there are two types: ordinary or special.

An ordinary resolution requires the affirmative vote of a majority of the votes of those persons voting at a meeting at which there is a quorum. A special resolution requires the affirmative vote of not less than three quarters of the persons voting at a meeting at which there is a quorum. Any AGM requires 21 clear days' notice. The notice period for any other general meeting is 14 clear days subject to the company obtaining annual shareholder approval, failing which, a 21 clear day notice period will apply.

Liquidation rights; redemption provisions

In the event of a liquidation of bp, after payment of all liabilities and applicable deductions under UK laws and subject to the payment of secured creditors, the holders of bp preference shares would be entitled to the sum of (1) the capital paid up on such shares plus, (2) accrued and unpaid dividends and (3) a premium equal to the higher of (a) 10% of the capital paid up on the bp preference shares and (b) the excess of the average market price over par value of such shares on the LSE during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, bp may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolutions, by determination of the directors), and may issue shares that are to be or may be redeemed.

Variation of rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or on the adoption of a special resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the Articles of Association relating to proceedings at a general meeting apply, except that the quorum with respect to a meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one third or more of the shares of that class.

Shareholders' meetings and notices

Shareholders must provide bp with a postal or electronic address in the UK to be entitled to receive notice of shareholders' meetings. Holders of bp ADSs are entitled to receive notices under the terms of the deposit agreement relating to bp ADSs. The substance and timing of notices are described above under the heading Voting rights.

Under the Act, the AGM of shareholders must be held once every year, within each six month period beginning with the day following the company's accounting reference date. All general meetings shall be held at a time and place determined by the directors. If any shareholders' meeting is adjourned for lack of quorum, notice of the time and place of the adjourned meeting may be given in any lawful manner, including electronically. Powers exist for action to be taken either before or at the meeting by authorized officers to ensure its orderly conduct and safety of those attending.

The directors have power to convene a general meeting which is a hybrid meeting, that is to provide facilities for shareholders to attend a meeting which is being held at a physical place by electronic means as well (but not to convene a purely electronic meeting).

The provisions of the Articles of Association in relation to satellite meetings permit facilities being provided by electronic means to allow those persons at each place to participate in the meeting.

Limitations on voting and shareholding

There are no limitations, either under the laws of the UK or under the company's Articles of Association, restricting the right of non-resident or foreign owners to hold or vote bp ordinary or preference shares in the company other than limitations that would generally apply to all of the shareholders and limitations applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

Disclosure of interests in shares

The Act permits a public company to give notice to any person whom the company believes to be or, at any time during the three years prior to the issue of the notice, to have been interested in its voting shares requiring them to disclose certain information with respect to those interests. Failure to supply the information required may lead to disenfranchisement of the relevant shares and a prohibition on their transfer and receipt of dividends and other payments in respect of those shares and any new shares in the company issued in respect of those shares. In this context the term 'interest' is widely defined and will generally include an interest of any kind whatsoever in voting shares, including any interest of a holder of bp ADSs.

Called-up share capital

Details of the allotted, called-up and fully-paid share capital at 31 December 2020 are set out in Financial statements – Note 31. In accordance with institutional investor guidelines, the company deems it appropriate to grant authority to the directors to allot shares and other securities and to disapply pre-emption rights by way of shareholders' resolutions at each AGM in place of authority granted by virtue of the company's Articles of Association. At the AGM on 27 May 2020, authorization was given to the directors to allot shares in the company and to grant rights to subscribe for, or to convert any security into, shares in the company up to an aggregate nominal amount as set out in the Notice of Meeting 2020. These authorities were given for the period until the next AGM in 2021 or 27 August 2021, whichever is the earlier. These authorities are renewed annually at the AGM.

Company records and service of notice

In relation to notices not covered by the Act, the reference to notice by advertisement in a national newspaper also includes advertisements via other means such as a public announcement.

Purchases of equity securities by the issuer and affiliated purchasers

In November 2017 bp began a share repurchase or buyback programme (the programme). The sole purpose of the programme was to reduce the issued share capital of the company to offset the ongoing dilutive effect of scrip dividends over time, as announced by the company on 31 October 2017. In January 2020 the share dilution buyback programme had fully offset the impact of scrip dilution since the third quarter 2017. Authorization for the company to make market purchases (as defined in section 693(4) of the Companies Act 2006) of ordinary shares with a nominal value of $0.25 each in the company was renewed at the company's 2020 AGM covering the period until the date of the company's 2021 AGM or 27 August 2021, whichever is earlier. The maximum number of ordinary shares to be purchased under this authority will not exceed 2,025,610,110 ordinary shares. The shares purchased will be cancelled.

The following table provides details of ordinary share purchases made (1) under the programme and (2) by the Employee Share Ownership Plans (ESOPs) and other purchases of ordinary shares and ADSs made to satisfy the requirements of certain employee share-based payment plans.

	Total number of shares purchased[a]	**Average price paid per share $**	Number of shares purchased by ESOPs or for certain employee share-based plans[b]	Number of shares purchased as part of the buyback programme[c]	Maximun approximate dollar value of shares yet to be purchased under the programme $ million
2020					
January 7 - January 28	**120,057,464**	**6.47**	Nil	120,057,464	N/A
February	**Nil**				N/A
March	**Nil**				N/A
April	**Nil**				N/A
May	**Nil**				N/A
June	**Nil**				N/A
July	**Nil**				N/A
August	**Nil**				N/A
September	**Nil**				N/A
October	**Nil**				N/A
November	**Nil**				N/A
December	**Nil**				N/A
2021					
January 11	**285,552**	**3.98**	285,552	Nil	N/A
February (to February 26)	**Nil**				N/A

[a] All share purchases were of ordinary shares of 25 cents each and/or ADSs (each representing six ordinary shares) and were on/open market transactions.

[b] Transactions represent the purchases of ADSs made to satisfy requirements of certain employee share-based payment plans.

[c] The company announced its intent to commence the programme on 31 October 2017 and announced further details and commencement of the programme on 15 November 2017. The programme was completed in January 2020. At the AGM on 27 May 2020, authorization was given to the company to repurchase up to 2,025,610,110 ordinary shares, for the period ending on the date of the AGM in 2021 or 27 August 2021, whichever is the earlier. This authorization is renewed annually at the AGM. The total number of ordinary shares repurchased during 2020 under the programme was 120,057,464 at a cost of $776 million (including fees and stamp duty) representing 0.59% of the company's issued share capital excluding shares held in treasury on 31 December 2020. All ordinary shares repurchased in 2020 under the programme were cancelled in order to reduce the company's issued share capital.

Fees and charges payable by ADS holders

The Depositary collects fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of the distributable property to pay the fees.

The charges of the Depositary payable by investors are as follows:

Type of service	Depositary actions	Fee
Depositing or substituting the underlying shares	Issuance of ADSs against the deposit of shares, including deposits and issuances in respect of: • Share distributions, stock splits, rights, merger. • Exchange of securities or other transactions or event or other distribution affecting the ADSs or deposited securities.	$5.00 per 100 ADSs (or portion thereof) evidenced by the new ADSs delivered.
Selling or exercising rights	Distribution or sale of securities, the fee being an amount equal to the fee for the execution and delivery of ADSs that would have been charged as a result of the deposit of such securities.	$5.00 per 100 ADSs (or portion thereof).
Withdrawing an underlying share	Acceptance of ADSs surrendered for withdrawal of deposited securities.	$5.00 for each 100 ADSs (or portion thereof) evidenced by the ADSs surrendered.
Expenses of the Depositary	Expenses incurred on behalf of holders in connection with: • Stock transfer or other taxes and governmental charges. • Delivery by cable, telex, electronic and facsimile transmission. • Transfer or registration fees, if applicable, for the registration of transfers of underlying shares. • Expenses of the Depositary in connection with the conversion of foreign currency into US dollars (which are paid out of such foreign currency).	Expenses payable are subject to agreement between the company and the Depositary by billing holders or by deducting charges from one or more cash dividends or other cash distributions.
Dividend fees	ADS holders who receive a cash dividend are charged a fee which bp uses to offset the costs associated with administering the ADS programme.	The Deposit Agreement provides that a fee of $0.05 or less per ADS can be charged. The current fee is $0.02 per bp ADS per calendar year (equivalent to $0.005 per bp ADS per quarter per cash distribution).
Global Invest Direct (GID) Plan	New investors and existing ADS holders can buy, sell or reinvest dividends into further bp ADSs by enrolling in bp's GID Plan, sponsored and administered by the Depositary.	Cost per transaction is $2.00 for recurring, $2.00 for one-time automatic investments, and $5.00 for investment made by check. Dividend reinvestment is 5% of the dividend amount up to a maximum of $5.00. Purchase trading commission is $0.12 per share.

Fees and payments made by the Depositary to the issuer

The Depositary has agreed to reimburse certain company expenses related to the company's ADS programme and incurred by the company in connection with the ADS programme arising during the year ended 31 December 2020. The Depositary reimbursed to the company, or paid amounts on the company's behalf to third parties, or waived its fees and expenses, of $18,936,081.43 for the year ended 31 December 2020.

The table below sets out the types of expenses that the Depositary has agreed to reimburse and the fees it has agreed to waive for standard costs associated with the administration of the ADS programme relating to the year ended 31 December 2020.

Category of expense reimbursed, waived or paid directly to third parties	Amount reimbursed, waived or paid directly to third parties for the year ended 31 December 2020
Fees for delivery and surrender of bp ADSs	1,267,682.60
Dividend fees[a]	17,668,398.83
Total	18,936,081.43

[a] Dividend fees are charged to ADS holders who receive a cash distribution, which bp uses to offset the costs associated with administering the ADS programme.

Under certain circumstances, including removal of the Depositary or termination of the ADR programme by the company, the company is required to repay the Depositary certain amounts reimbursed and/or expenses paid to or on behalf of the company during the 12-month period prior to notice of removal or termination.

Documents on display

The *bp Annual Report and Form 20-F 2020* is available online at *bp.com/annualreport*. To obtain a hard copy of bp's complete audited financial statements, free of charge, UK based shareholders should contact bp Distribution Services by calling +44 (0) 800 037 2172 or by emailing *bpdistributionservices@bp.com*. If based in the US or Canada shareholders should contact Issuer Direct by calling +1 888 301 2505 or by emailing *bpreports@issuerdirect.com*.

The company is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, the company files its Annual Report and Form 20-F and other related documents with the SEC. The SEC maintains an internet site at *www.sec.gov* that contains reports and other information regarding issuers, including bp, that file electronically with the SEC. bp's SEC filings are also available at *bp.com/sec*. bp discloses in this report (see Corporate governance practices (Form 20-F Item 16G) on page 326) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

Shareholding administration

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payment options or to change the way you receive your company documents (such as the bp *Annual Report and Form 20-F* and *Notice of bp Annual General Meeting*) please contact the bp Registrar or the bp ADS Depositary.

Ordinary and preference shareholders

The bp Registrar, Link Group, Central Square,
29 Wellington Street,
Leeds, LS1 4DL
Freephone in UK 0800 701107
From outside the UK +44 (0)371 277 1014

ADS holders

bp Shareowner Services
PO Box 64504, St Paul, MN 55164-0504, US
Toll-free in US and Canada +1 877 638 5672
From outside the US and Canada +1 651 306 4383

2021 shareholder calendar[a]

26 Mar 2021	Fourth quarter interim dividend payment for 2020
27 April 2021	First quarter results announced
7 May 2021	Record date (to be eligible for the first quarter interim dividend)
12 May 2021	Annual general meeting
18 Jun 2021	First quarter interim dividend payment for 2021
2 Jul 2021	8% and 9% preference shares record date
27 Jul 2021	Second quarter results announced
30 Jul 2021	8% and 9% preference shares dividend payment
6 Aug 2021	Record date (to be eligible for the second quarter interim dividend)
24 Sep 2021	Second quarter interim dividend payment for 2021
2 Nov 2021	Third quarter results announced
12 Nov 2021	Record date (to be eligible for the third quarter interim dividend)
17 Dec 2021	Third quarter interim dividend payment for 2021

[a] All future dates are provisional and may be subject to change. For the full calendar see *bp.com/financialcalendar*.

Glossary

Abbreviations

ADR
American depositary receipt.

ADS
American depositary share. 1 ADS = 6 ordinary shares.

Barrel (bbl)
159 litres, 42 US gallons.

bcf
Billion cubic feet.

bcfe
Billion cubic feet equivalent.

EVP
Executive vice president.

FPSO
Floating production, storage and offloading.

GAAP
Generally accepted accounting practice.

Gas
Natural gas.

gCO_2e/MJ
Grams of carbon dioxide equivalent per megajoule of energy.

GHG
Greenhouse gas.

GRI
Global Reporting Initiative.

$GtCO_2$
Gigatonnes of carbon dioxide.

GWh
Gigawatt hour.

HSSE
Health, safety, security and environment.

IFRS
International Financial Reporting Standards.

Kb/d
Thousand barrels per day.

KPIs
Key performance indicators.

kt
Thousand tonnes.

LNG
Liquefied natural gas.

LPG
Liquefied petroleum gas.

mb/d
Thousand barrels per day.

Mbbl
Million barrels.

mboe/d
Thousand barrels of oil equivalent per day.

mmb/d
Million barrels per day.

mmboe/d
Million barrels of oil equivalent per day.

mmBtu
Million British thermal units.

mmcf/d
Million cubic feet per day.

Mte
Million tonnes.

$MteCO_2e$
Million tonnes of CO_2 equivalent.

Mtpa
Million tonnes per annum.

NGLs
Natural gas liquids.

PSA
Production-sharing agreement.

PTA
Purified terephthalic acid.

RC
Replacement cost.

SEC
The United States Securities and Exchange Commission.

TWh
Terawatt hour.

SVP
Senior vice president.

Definitions

Unless the context indicates otherwise, the definitions for the following glossary terms are given below.

Non-GAAP measures are sometimes referred to as alternative performance measures.

CA100+ resolution glossary

CA100+ resolution
The CA100+ resolution means the special resolution requisitioned by Climate Action 100+ and passed at bp's 2019 Annual General Meeting, the text of which is set out below.

Special resolution: Climate Action 100+ shareholder resolution on climate change disclosures.
That in order to promote the long term success of the company, given the recognised risks and opportunities associated with climate change, we as shareholders direct the company to include in its strategic report and/or other corporate reports, as appropriate, for the year ending 2019 onwards, a description of its strategy which the board considers, in good faith, to be consistent with the goals of Articles 2.1(a)(1) and 4.1(2) of the Paris Agreement(3) (the 'Paris goals'), as well as:

(1) Capital expenditure: how the company evaluates the consistency of each new material capex investment, including in the exploration, acquisition or development of oil and gas resources and reserves and other energy sources and technologies, with (a) the Paris goals and separately (b) a range of other outcomes relevant to its strategy.

(2) Metrics and targets: the company's principal metrics and relevant targets or goals over the short, medium and/or long-term, consistent with the Paris goals, together with disclosure of:

a. The anticipated levels of investment in (i) oil and gas resources and reserves; and (ii) other energy sources and technologies.

b. The company's targets to promote reductions in its operational greenhouse gas emissions, to be reviewed in line with changing protocols and other relevant factors

c. The estimated carbon intensity of the company's energy products and progress on carbon intensity over time.

d. Any linkage between the above targets and executive remuneration.

(3) Progress reporting: an annual review of progress against (1) and (2) above.

Such disclosure and reporting to include the criteria and summaries of the methodology and core assumptions used, and to omit commercially confidential or competitively sensitive information and be prepared at reasonable cost; and provided that nothing in this resolution shall limit the company's powers to set and vary its strategy, or associated targets or metrics, or to take any action which it believes in good faith, would best promote the long-term success of the company.

The Paris goals

(1) Article 2.1(a) of the Paris Agreement states the goal of 'Holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change'.

(2) Article 4.1 of the Paris Agreement: In order to achieve the long-term temperature goal set out in Article 2, parties aim to reach global peaking of greenhouse gas emissions as soon as possible, recognizing that peaking will take longer for developing country parties, and to undertake rapid reductions thereafter in accordance with best available science, so as to achieve a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases in the second half of this century, on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty.

(3) U.N. Framework Convention on Climate Change Conference of Parties, Twenty-First Session, Adoption of the Paris Agreement, U.N. Doc. FCCC/CP/2015/L.9/Rev.1 (Dec. 12, 2015).

New material capex investment

For the purposes of the 2020 evaluation discussed on pages 28-32, 'new material capex investment' means a decision taken by the resource commitment meeting (RCM) in 2020 to incur inorganic or organic investments greater than $250 million that relate to a new project or asset, extending an existing project or asset, or acquiring or increasing a share in a project, asset or entity.

There were three investments that met the above criteria in 2020.

Material capex evaluation: Paris-consistency quantitative tests.

For the purposes of evaluating material capex investments for consistency with the Paris goals, two quantitative tests were applied, see page 32.

1. Operational carbon intensity (CI)

   The annual average operational GHG emissions (TeCO_2e/unit), divided by the relevant unit of output:

   - per thousand barrels of oil equivalent in Upstream
   - per utilized equivalent distillation capacity in refining
   - per thousand tonnes in petrochemicals.

Net zero aims and ambition glossary

Net zero

References to global net zero in the phrase, 'to help the world get to net zero', means achieving '...a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases...on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty', as set out in Article 4(1) of the Paris Agreement.

References to net zero for bp in the context of our ambition and Aims 1 and 2 as set out on page 49 (such as 'be a net zero company by 2050 or sooner'), means achieving a balance between (a) the relevant Scope 1 and 2 emissions (for our Aim 1), or Scope 3 emissions (for our Aim 2), and (b) the aggregate of applicable deductions from qualifying activities such as sinks under our methodology at the applicable time.

Emissions from the carbon in our Upstream oil and gas production

Estimated CO_2 emissions from the combustion of upstream production of crude oil, natural gas and natural gas liquids (NGLs) on a bp equity-share basis based on bp's net share of production, excluding bp's share of Rosneft production and assuming that all produced volumes undergo full stoichiometric combustion to CO_2.

Average emissions intensity of marketed energy products

The weighted average GHG emissions per unit of energy delivered (in grams CO_2e/MJ), estimated in respect of marketing sales of energy products. GHG emissions are estimated on a lifecycle basis covering production, distribution and use of the relevant products (assuming full stoichiometric combustion of the product to CO_2).

Methane intensity

Methane intensity refers to the amount of methane emissions from bp's operated upstream oil and gas assets as a percentage of the total gas that goes to market from those operations. Our methodology is aligned with the Oil and Gas Climate Initiative's (OGCI).

Sustainable emissions reductions (SER)

SERs result from actions or interventions that have led to ongoing reductions in Scope 1 (direct) and/or Scope 2 (indirect) greenhouse gas (GHG) emissions (carbon dioxide and methane) such that GHG emissions would have been higher in the reporting year if the intervention had not taken place. SERs must meet three criteria: a specific intervention that has reduced GHG emissions, the reduction must be quantifiable and the reduction is expected to be ongoing. Reductions are reportable for a 12-month period from the start of the intervention/action.

Adjusted EBIDA

Non-GAAP measure. Adjusted EBIDA is defined as underlying replacement cost profit before interest and tax, add back depreciation, depletion and amortization and exploration expenditure written-off (net of non-operating items), less taxation on an underlying RC basis. bp believes that adjusted EBIDA is a useful measure for investors because it is a measure closely tracked by management to evaluate bp's operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is profit or loss before interest and tax. Adjusted EBIDA per share is calculated based on the shares in issue at period-end.

Adjusted effective tax rate (ETR)

Non-GAAP measure. The adjusted ETR is calculated by dividing taxation on an underlying replacement cost (RC) basis excluding the impact of reductions in the rate of the UK North Sea supplementary charge in 2016 by underlying RC profit or loss before tax. Taxation on an underlying RC basis is taxation on a RC basis for the period adjusted for taxation on non-operating items and fair value accounting effects, and certain foreign exchange impacts on the group's tax charge for the period. Information on underlying RC profit or loss is provided below. bp believes it is helpful to disclose the adjusted ETR because this measure may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period. A reconciliation to GAAP information is provided on page 348.

Associate

An entity over which the group has significant influence and that is neither a subsidiary nor a joint arrangement of the group. Significant influence is the power to participate in the financial and operating policy decisions of the investee but is not control or joint control over those policies.

Bioenergy production

Bioenergy production is average thousands of barrels of biofuel production per day during the period covered, net to bp. This includes equivalent ethanol production, bp Bunge biopower for grid export, biogas and refining co-processing and standalone hydrogenated vegetable oil (HVO).

Brent
A trading classification for North Sea crude oil that serves as a major benchmark price for purchases of oil worldwide.

Capital expenditure
Total cash capital expenditure as stated in the group cash flow statement.

Castrol sales and other operating revenues
Castrol sales and other operating revenues, are sales and other operating revenues generated by our Castrol business.

Commodity trading contracts
bp participates in regional and global commodity trading markets in order to manage, transact and hedge the crude oil, refined products and natural gas that the group either produces or consumes in its manufacturing operations. The range of contracts the group enters into in its commodity trading operations is described below. Using these contracts, in combination with rights to access storage and transportation capacity, allows the group to access advantageous pricing differences between locations, time periods and grades.

Exchange-traded commodity derivatives
Contracts that are typically in the form of futures and options traded on a recognized exchange, such as Nymex and ICE. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate; the main product grades, such as gasoline and gasoil; and for natural gas and power. Gains and losses, otherwise referred to as variation margin, are generally settled on a daily basis with the relevant exchange. These contracts are used for the trading and risk management of crude oil, refined products, and natural gas and power. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

Over-the-counter (OTC) contracts
Contracts that are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties or through brokers, others may be cleared by a central clearing counterparty. These contracts can be used both for trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in sales and other operating revenues for accounting purposes. Many grades of crude oil bought and sold use standard contracts including US domestic light sweet crude oil, commonly referred to as West Texas Intermediate, and a standard North Sea crude blend – Brent, Forties, Oseberg and Ekofisk (BFOE). Forward contracts are used in connection with the purchase of crude oil supplies for refineries and for marketing and sales of the group's oil production and refined products. The contracts typically contain standard delivery and settlement terms. These transactions call for physical delivery of oil with consequent operational and price risk. However, various means exist and are used from time to time, to settle obligations under the contracts in cash rather than through physical delivery. Physically settled BFOE contracts delivered by cargo additionally specify a standard volume and tolerance.

Gas and power OTC markets are highly developed in North America and the UK, where commodities can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price, with delivery and settlement at a future date. Typically, the contracts specify delivery terms for the underlying commodity. Some of these transactions are not settled physically as they can be net settled by transacting offsetting sale or purchase contracts for the same location and delivery period. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically, volume, price and term (e.g. daily, monthly and balance of month) are the main variable contract terms.

Swaps are typically contractual obligations to exchange cash flows between two parties. A typical swap transaction usually references a floating price and a fixed price with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell crude, oil products, natural gas or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry. Typically, netting agreements are used to limit credit exposure and support liquidity.

Spot and term contracts
Spot contracts are contracts to purchase or sell a commodity at the market price prevailing on or around the delivery date when title to the inventory is taken. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. As such, these transactions result in physical delivery with operational and price risk. Spot and term contracts typically relate to purchases of crude for a refinery, products for marketing, or third-party natural gas, or sales of the group's oil production, oil products or gas production to third parties. For accounting purposes, spot and term sales are included in sales and other operating revenues when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.

Consolidation adjustment – UPII
Unrealized profit in inventory arising on inter-segment transactions.

Convenience gross margin
Non-GAAP measure. Convenience gross margin comprises store gross margin as well as other merchandise and service contribution, not considered as retail fuels or store gross margin, received from the retail service stations operated under a bp brand, excluding equity-accounted entities.

Convenience, retail fuels and electrification gross margin
Non-GAAP measure. Convenience, retail fuels and electrification gross margin is RC profit before interest and tax for Downstream, adjusted for non-operating items and fair value accounting effects to derive underlying RC profit before interest and tax. Downstream underlying RC profit before interest and tax is further adjusted by subtracting underlying RC profit before interest and tax for the petrochemicals, refining and trading and lubricants businesses; adding-back depreciation, depletion and amortization, production and manufacturing, distribution and administration expenses for fuels (excluding refining and trading); subtracting earnings from equity-accounted entities in fuels (excluding refining and trading) and gross margin for aviation, B2B and midstream businesses.

Margin share for convenience and electrification is the ratio of convenience and electrification gross margin to total consumer energy (retail fuels and electrification) and convenience gross margin.

bp believes it is helpful to disclose the margin share from convenience and electrification because this measure may help investors to understand and evaluate, in the same way as management, our progress against our strategic objectives of redefining convenience and scaling up our next-gen mobility solutions. The nearest GAAP measures of the numerator and denominator are RC profit before interest and tax. A reconciliation to GAAP information is provided on page 318.

We are unable to present forward-looking information of the nearest GAAP measures of the numerator and denominator for margin share for convenience and electrification, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to calculate a meaningful comparable GAAP forward-looking financial measure. These items include inventory holding gains or losses, that is difficult to predict in advance in order to include in a GAAP estimate.

Cumulative cash costs reductions
Non-GAAP measure. Cash costs are a subset of production and manufacturing expenses plus distribution and administration expenses and they exclude costs that are classified as non-operating items. They represent the substantial majority of the remaining expenses in these line items but exclude certain costs that are variable, primarily with volumes (such as freight costs). Management believes that cash costs is a performance measure that provides investors with useful information regarding the company's financial performance, because it considers these expenses to be the principal operating and overhead expenses that are most directly under their control although they also include certain foreign exchange and commodity price effects. Cumulative cash cost reductions in 2021 compared to 2019, as applicable to the directors' remuneration usage, are further defined as 2021 exit rate, less agreed portfolio changes compared to 2019 baseline.

Customer touchpoints

Customer touchpoints are the number of retail customer transactions per day on bp forecourts globally. These include transactions involving fuel and/or convenience across all channels of trade.

Developed renewables to final investment decision (FID)

Total generating capacity for assets developed to FID by all entities where bp has an equity share (proportionate to equity share). If asset is subsequently sold bp will continue to record capacity as developed to FID. If bp equity share increases developed capacity to FID will increase proportionately to share increase for any assets where bp held equity at the point of FID.

Divestment proceeds

Disposal proceeds as per the group cash flow statement.

Dividend yield

Sum of the four quarterly dividends announced in respect of the year as a percentage of the year-end share price.

Effective tax rate (ETR) on replacement cost (RC) profit or loss

Non-GAAP measure. The ETR on RC profit or loss is calculated by dividing taxation on a RC basis by RC profit or loss before tax. Information on RC profit or loss is provided below. bp believes it is helpful to disclose the ETR on RC profit or loss because this measure excludes the impact of price changes on the replacement of inventories and allows for more meaningful comparisons between reporting periods. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period. A reconciliation to GAAP information is provided on page 348.

Electric vehicle charge points

Defined as charge points operated by either bp or a bp joint venture.

Fair value accounting effects

Non-GAAP adjustments to our IFRS profit or loss. We use derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products. Under IFRS, these inventories are recorded at historical cost. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in the income statement. This is because hedge accounting is either not permitted or not followed, principally due to the impracticality of effectiveness-testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories are not recognized until the commodity is sold in a subsequent accounting period. Gains and losses on the related derivative commodity contracts are recognized in the income statement, from the time the derivative commodity contract is entered into, on a fair value basis using forward prices consistent with the contract maturity.

bp enters into physical commodity contracts to meet certain business requirements, such as the purchase of crude for a refinery or the sale of bp's gas production. Under IFRS these physical contracts are treated as derivatives and are required to be fair valued when they are managed as part of a larger portfolio of similar transactions. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

IFRS require that inventory held for trading is recorded at its fair value using period-end spot prices, whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices, resulting in measurement differences.

bp enters into contracts for pipelines and other transportation, storage capacity, oil and gas processing and liquefied natural gas (LNG) that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments that are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that bp manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. bp calculates this difference for consolidated entities by comparing the IFRS result with management's internal measure of performance. Under management's internal measure of performance the inventory, transportation and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period. The fair values of derivative instruments used to risk manage certain oil, gas and other contracts, are deferred to match with the underlying exposure and the commodity contracts for business requirements are accounted for on an accruals basis. We believe that disclosing management's estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole.

Fair value accounting effects also include changes in the fair value of the near-term portions of LNG contracts that fall within bp's risk management framework. LNG contracts are not considered derivatives, because there is insufficient market liquidity, and they are therefore accrual accounted under IFRS. However, oil and natural gas derivative financial instruments (used to risk manage the near-term portions of the LNG contracts) are fair valued under IFRS. The fair value accounting effect reduces timing differences between recognition of the derivative financial instruments used to risk manage the LNG contracts and the recognition of the LNG contracts themselves, which therefore gives a better representation of performance in each period.

In addition, from 2020 fair value accounting effects include changes in the fair value of derivatives entered into by the group to manage currency exposure and interest rate risks relating to hybrid bonds to their respective first call periods. The hybrid bonds which were issued on 17 June 2020 are classified as equity instruments and were recorded in the balance sheet at that date at their USD equivalent issued value. Under IFRS these equity instruments are not remeasured from period to period, and do not qualify for application of hedge accounting. The derivative instruments relating to the hybrid bonds, however, are required to be recorded at fair value with mark to market gains and losses recognized in the income statement. Therefore, measurement differences in relation to the recognition of gains and losses occur. The fair value accounting effect, which is reported in the Other businesses and corporate segment, eliminates the fair value gains and losses of these derivative financial instruments that are recognized in the income statement. We believe that this gives a better representation of performance, by more appropriately reflecting the economic effect of these risk management activities, in each period.

Finance debt ratio

Finance debt ratio is defined as the ratio of finance debt to the total of finance debt plus total equity.

Free cash flow

Operating cash flow less net cash used in investing activities and lease liability payments included in financing activities, as presented in the group cash flow statement.

Gearing and net debt

Non-GAAP measures. 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 currency exchange and interest rate risks relating to finance debt, for which hedge accounting is applied, less cash and cash equivalents. Gearing is defined as the ratio of net debt to the total of net debt plus total equity. 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 total equity. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. See Financial statements – Note 27 for information on finance debt, which is the nearest equivalent measure to net debt on an IFRS basis. The nearest equivalent GAAP measure to gearing on an IFRS basis is finance debt ratio.

We are unable to present reconciliations of forward-looking information for gearing to finance debt ratio, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable GAAP forward-looking financial measure. These items include fair value asset (liability) of hedges related to finance debt and cash and cash equivalents, that are difficult to predict in advance in order to include in a GAAP estimate.

Gearing including leases and net debt including leases
Non-GAAP measure. Net debt including leases is calculated as net debt plus lease liabilities, less the net amount of partner receivables and payables relating to leases entered into on behalf of joint operations. Gearing including leases is defined as the ratio of net debt including leases to the total of net debt including leases plus total equity. bp believes these measures provide useful information to investors as they enable investors to understand the impact of the group's lease portfolio on net debt and gearing. See Financial statements – Note 27 for information on finance debt, which is the nearest equivalent measure to net debt including leases on an IFRS basis. The nearest equivalent GAAP measure to gearing including leases on an IFRS basis is finance debt ratio.

Henry Hub
A distribution hub on the natural gas pipeline system in Erath, Louisiana, that lends its name to the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange and the over-the-counter swaps traded on Intercontinental Exchange.

Hydrocarbons
Liquids and natural gas. Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Inorganic capital expenditure
A subset of capital expenditure on a cash basis and is a non-GAAP measure. Inorganic capital expenditure comprises consideration in business combinations and certain other significant investments made by the group. It is reported on a cash basis. bp believes that this measure provides useful information as it allows investors to understand how bp's management invests funds in projects which expand the group's activities through acquisition. Further information and a reconciliation to GAAP information is provided on page 303.

Inventory holding gains and losses
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. See Replacement cost (RC) profit or loss definition below.

Joint arrangement
An arrangement in which two or more parties have joint control.

Joint control
Contractually agreed sharing of control over an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Joint operation
A joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement.

Joint venture
A joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement.

Liquids
Comprises crude oil, condensate and natural gas liquids. For the Upstream segment, it also includes bitumen.

LNG portfolio
LNG portfolio refers to bp group's LNG equity production plus additional long-term merchant LNG volumes.

LNG train
An LNG train is a processing facility used to liquefy and purify natural gas in the formation of LNG.

Low carbon energy / low carbon technologies
Low carbon (renewable) electricity; bio-energy; electrification; future mobility solutions; carbon capture, use and storage (CCUS); "blue" or "green" hydrogen; and trading in low carbon products. Note that, while there is some overlap, these terms do not mean the same as bp's strategic focus area of "low carbon electricity and energy".

Low carbon investment / investment in low carbon energy / investment in low carbon
Capital expenditure on low carbon energy or technologies.

Low carbon and other energy transition activities
Low carbon energy / technologies as described above, together with convenience; integrated gas and power; bp Ventures and Launchpad.

Major projects
Have a bp net investment of at least $250 million, or are considered to be of strategic importance to bp or of a high degree of complexity.

Margin share for convenience and electrification
Non-GAAP measure. See Convenience, retail fuels and electrification gross margin definition.

Non-operating items
Charges and credits are included in the financial statements that bp discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers not to be part of underlying business operations and are disclosed in order to enable investors better to understand and evaluate the group's reported financial performance. Non-operating items within equity-accounted earnings are reported net of incremental income tax reported by the equity-accounted entity. An analysis of non-operating items by segment and type is shown on page 304.

Operating cash flow
Net cash provided by (used in) operating activities as stated in the group cash flow statement. When used in the context of a segment rather than the group, the terms refer to the segment's share thereof.

Operating cash flow excluding Gulf of Mexico oil spill payments
Non-GAAP measure. It is calculated by excluding post-tax operating cash flows relating to the Gulf of Mexico oil spill from net cash provided by operating activities as reported in the group cash flow statement. bp believes net cash provided by operating activities excluding amounts related to the Gulf of Mexico oil spill is a useful measure as it allows for more meaningful comparisons between reporting periods. The nearest equivalent measure on an IFRS basis is net cash provided by operating activities.

Operating management system (OMS)
bp's OMS helps us manage risks in our operating activities by setting out bp's principles for good operating practice. It brings together bp requirements on health, safety, security, the environment, social responsibility and operational reliability, as well as related issues, such as maintenance, contractor relations and organizational learning, into a common management system.

Organic capital expenditure
A subset of capital expenditure on a cash basis and is a non-GAAP measure. Organic capital expenditure comprises capital expenditure less inorganic capital expenditure. bp believes that this measure provides useful information as it allows investors to understand how bp's management invests funds in developing and maintaining the group's assets. An analysis of organic capital expenditure by segment and region, and a reconciliation to GAAP information is provided on page 303.

We are unable to present reconciliations of forward-looking information for organic capital expenditure to total cash capital expenditure, because without unreasonable efforts, we are unable to forecast accurately the adjusting item, inorganic capital expenditure, that is difficult to predict in advance in order to derive the nearest GAAP estimate.

Production-sharing agreement / contract (PSA / PSC)
An arrangement through which an oil and gas company bears the risks and costs of exploration, development and production. In return, if exploration is successful, the oil company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of the production remaining after such cost recovery.

Readily marketable inventory (RMI)
RMI is inventory held and price risk-managed by our integrated supply and trading function (IST) which could be sold to generate funds if required. It comprises oil and oil products for which liquid markets are available and excludes inventory which is required to meet operational requirements and other inventory which is not price risk-managed. RMI is reported at fair value. Inventory held by the Downstream fuels business for the purpose of sales and marketing, and all inventories relating to the lubricants and petrochemicals businesses, are not included in RMI. bp believes that disclosing the amounts of RMI and paid-up RMI is useful to investors as it enables them to better understand and evaluate the group's inventories and liquidity position by enabling them to see the level of discretionary inventory held by IST and to see builds or releases of liquid trading inventory.

Paid-up RMI excludes RMI which has not yet been paid for. For inventory that is held in storage, a first-in first-out (FIFO) approach is used to determine whether inventory has been paid for or not. Unpaid RMI is RMI which has not yet been paid for by bp. RMI at fair value, Paid-up RMI and Unpaid RMI are non-GAAP measures. A reconciliation of total inventory as reported on the group balance sheet to paid-up RMI is provided on page 349.

Realizations
Realizations are the result of dividing revenue generated from hydrocarbon sales, excluding revenue generated from purchases made for resale and royalty volumes, by revenue generating hydrocarbon production volumes. Revenue generating hydrocarbon production reflects the bp share of production as adjusted for any production which does not generate revenue. Adjustments may include losses due to shrinkage, amounts consumed during processing, and contractual or regulatory host committed volumes such as royalties. For the Upstream segment, realizations include transfers between businesses.

Refining availability
Represents Solomon Associates' operational availability for bp-operated refineries, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory downtime.

Refining marker margin (RMM)
The average of regional indicator margins weighted for bp's crude refining capacity in each region. Each regional marker margin is based on product yields and a marker crude oil deemed appropriate for the region. The regional indicator margins may not be representative of the margins achieved by bp in any period because of bp's particular refinery configurations and crude and product slate.

Replacement cost (RC) profit or loss
Reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses from profit or loss. RC profit or loss is the measure of profit or loss that is required to be disclosed for each operating segment under IFRS. RC profit or loss for the group is a non-GAAP measure. Management believes this measure is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due to changes in prices as well as changes in underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, bp's management believes it is helpful to disclose this measure. The nearest equivalent measure on an IFRS basis is profit or loss attributable to bp shareholders. See Financial statements – Note 5. A reconciliation to GAAP information is provided on page 302.

RC profit or loss per share
Non-GAAP measure. Earnings per share is defined in Financial statements – Note 11. RC profit or loss per share is calculated using the same denominator. The numerator used is RC profit or loss attributable to bp shareholders rather than profit or loss attributable to bp shareholders. bp believes it is helpful to disclose the RC profit or loss per share because this measure excludes the impact of price changes on the replacement of inventories and allows for more meaningful comparisons between reporting periods. The nearest equivalent measure on an IFRS basis is basic earnings per share based on profit or loss for the period attributable to bp shareholders. A reconciliation to GAAP information is provided on page 348.

Renewables pipeline
Renewable projects satisfying criteria below to the point they can be considered developed to FID :

Site based projects have obtained land exclusivity rights, or for PPA based projects an offer has been made to the counterparty, or for auction projects pre-qualification criteria has been met, or for acquisition projects post a binding offer being accepted.

Reserves replacement ratio
The extent to which the year's production has been replaced by proved reserves added to our reserve base. The ratio is expressed in oil-equivalent terms and includes changes resulting from discoveries, improved recovery and extensions and revisions to previous estimates, but excludes changes resulting from acquisitions and disposals.

Retail sites
Retail sites include sites operated by dealers, jobbers, franchisees or brand licensees or joint venture (JV) partners, under the bp brand. These may move to and from the bp brand as their fuel supply agreement or brand licence agreement expires and are renegotiated in the normal course of business. Retail sites are primarily branded *bp*, *ARCO*, *Amoco*, *Aral* and *Thorntons*, and also includes sites in India through our Jio-bp JV.

Retail sites in growth markets
These are retail sites that are either bp branded or co-branded with our partners in China, Mexico and Indonesia and also include sites in India through our Jio-bp JV.

Return on average capital employed
Non-GAAP measure. Return on average capital employed (ROACE) is underlying replacement cost profit, after adding back non-controlling interest and interest expense net of tax (for 2016 and 2017 interest expense was net of notional tax at an assumed 35%), divided by average capital employed (total equity plus finance debt), excluding cash and cash equivalents and goodwill. Interest expense is finance costs excluding lease interest and the unwinding of the discount on provisions and other payables before tax. bp believes it is helpful to disclose the ROACE because this measure gives an indication of the company's capital efficiency. The nearest GAAP measures of the numerator and denominator are profit or loss for the period attributable to bp shareholders and total equity respectively. The reconciliation of the numerator and denominator is provided on page 349.

We are unable to present forward-looking information of the nearest GAAP measures of the numerator and denominator for ROACE, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to calculate a meaningful comparable GAAP forward-looking financial measure. These items include inventory holding gains or losses and interest net of tax, that are difficult to predict in advance in order to include in a GAAP estimate.

Strategic convenience sites
Strategic convenience sites are retail sites, within the bp portfolio, which both sell bp branded fuel and carry one of the strategic convenience brands (e.g. M&S, Rewe to Go). To be considered a strategic convenience brand the convenience offer should be a strategic differentiator in the market in which it operates. Strategic convenience site count includes sites under a pilot phase.

Subsidiary
An entity that is controlled by the bp group. Control of an investee exists when an investor is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee.

Surplus cash
Surplus cash refers to surplus of sources of cash including operating cash flow, joint venture loan repayments and divestment proceeds, over uses, including leases, Gulf of Mexico oil spill payments, hybrid servicing costs, dividend payments and cash capital expenditure.

Tier 1 and tier 2 process safety events
Tier 1 events are losses of primary containment from a process of greatest consequence – causing harm to a member of the workforce, damage to equipment from a fire or explosion, a community impact or exceeding defined quantities. Tier 2 events are those of lesser consequence. These represent reported incidents occurring within bp's operational HSSE reporting boundary. That boundary includes bp's own operated facilities and certain other locations or situations.

Tight oil and gas
Natural oil and gas reservoirs locked in hard sandstone rocks with low permeability, making the underground formation extremely tight.

Traded electricity
Traded electricity refers to sales data for physically delivered electricity.

Transition and low carbon investments
Capital expenditure on low carbon or other energy transition activities.

UK National Balancing Point
A virtual trading location for sale, purchase and exchange of UK natural gas. It is the pricing and delivery point for the Intercontinental Exchange natural gas futures contract.

Unconventionals
Resources found in geographic accumulations over a large area, that usually present additional challenges to development such as low permeability or high viscosity. Examples include shale gas and oil, coalbed methane, gas hydrates and natural bitumen deposits. These typically require specialized extraction technology such as hydraulic fracturing or steam injection.

Underlying effective tax rate (ETR)
Non-GAAP measure. The underlying ETR is calculated by dividing taxation on an underlying replacement cost (RC) basis by underlying RC profit or loss before tax. Taxation on an underlying RC basis is taxation on a RC basis for the period adjusted for taxation on non-operating items and fair value accounting effects, and certain foreign exchange impacts on the group's tax charge for the period. Information on underlying RC profit or loss is provided below. bp believes it is helpful to disclose the underlying ETR because this measure may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period. A reconciliation to GAAP information is provided on page 348.

We are unable to present reconciliations of forward-looking information for underlying ETR to ETR on profit or loss for the period, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable GAAP forward-looking financial measure. These items include the taxation on inventory holding gains and losses, non-operating items and fair value accounting effects, that are difficult to predict in advance in order to include in a GAAP estimate.

Underlying production
Production after adjusting for acquisitions and divestments and entitlement impacts in our production-sharing agreements (PSAs). 2021 underlying production, when compared with 2020, is production after adjusting for acquisitions and divestments, curtailments, and entitlement impacts in our production-sharing agreements/contracts and technical service contract.

Underlying replacement cost (RC) profit or loss
Non-GAAP measure. RC profit or loss after adjusting for non-operating items and fair value accounting effects. Fair value accounting effects are non-GAAP adjustments. See pages 304 and 305 for additional information on the non-operating items and fair value accounting effects that are used to arrive at underlying RC profit or loss in order to enable a full understanding of the events and their financial impact. bp believes that underlying RC profit or loss is a useful measure for investors because it is a measure closely tracked by management to evaluate bp's operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, year on year, by adjusting for the effects of these non-operating items and fair value accounting effects.

The nearest equivalent measure on an IFRS basis for the group is profit or loss for the year attributable to bp shareholders. The nearest equivalent measure on an IFRS basis for segments is RC profit or loss before interest and taxation. A reconciliation to GAAP information is provided on page 302.

Underlying replacement cost (RC) profit or loss per share
Non-GAAP measure. Earnings per share is defined Financial statements – Note 11. Underlying RC profit or loss per share is calculated using the same denominator. The numerator used is underlying RC profit or loss attributable to bp shareholders rather than profit or loss attributable to bp shareholders. bp believes it is helpful to disclose the underlying RC profit or loss per share because this measure may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is basic earnings per share based on profit or loss for the period attributable to bp shareholders. A reconciliation to GAAP information is provided on page 348.

Upstream plant reliability
bp-operated Upstream plant reliability is calculated taking 100% less the ratio of total unplanned plant deferrals divided by installed production capacity. Unplanned plant deferrals are associated with the topside plant and where applicable the subsea equipment (excluding wells and reservoir). Unplanned plant deferrals include breakdowns, which does not include Gulf of Mexico weather related downtime.

Upstream unit production costs
Upstream unit production costs are calculated as production costs divided by units of production. Production costs do not include ad valorem and severance taxes. Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts disclosed are for bp subsidiaries only and do not include bp's share of equity-accounted entities.

West Texas Intermediate (WTI)
A light sweet crude oil, priced at Cushing, Oklahoma, which serves as a benchmark price for purchases of oil in the US.

Working capital
Movements in inventories and other current and non-current assets and liabilities as stated in the group cash flow statement.

Trade marks

Trade marks of the bp group appear throughout this report. They include:

Aral, ARCO, BP, bp pulse, Castrol, Amoco, Thorntons

Trade marks:

Amazon Web Services – a trademark of amazon.com, inc

REWE to Go – a registered trade mark of REWE.

Non-GAAP measures reconciliations

Reconciliation of basic earnings per ordinary share to RC profit (loss) per share and to underlying RC profit per share

					Per ordinary share – cents
	2020	2019	2018	2017	2016
Profit (loss) for the year[a]	**(100.42)**	19.84	46.98	17.20	0.61
Inventory holding (gains) losses, before tax	**14.18**	(3.29)	4.01	(4.32)	(8.52)
Taxation charge (credit) on inventory holding gains and losses	**(3.29)**	0.77	(0.99)	1.14	2.58
RC profit (loss) for the year	**(89.53)**	17.32	50.00	14.02	(5.33)
Net (favourable) adverse impact of non-operating items and fair value accounting effects, before tax	**82.33**	40.73	16.93	18.94	35.99
Taxation charge (credit) on non-operating items and fair value accounting effects	**(20.94)**	(8.81)	(3.23)	(1.65)	(16.87)
Underlying RC profit for the year	**(28.14)**	49.24	63.70	31.31	13.79

[a] Profit attributable to bp shareholders.

Reconciliation of effective tax rate (ETR) to ETR on RC profit or loss and adjusted ETR

Taxation (charge) credit

					$ million
	2020	2019	2018	2017	2016
Taxation on profit or loss for the year	**4,159**	(3,964)	(7,145)	(3,712)	2,467
Adjusted for taxation on inventory holding gains and losses	**667**	(156)	198	(225)	(483)
Taxation on a RC profit or loss basis	**3,492**	(3,808)	(7,343)	(3,487)	2,950
Adjusted for taxation on non-operating items and fair value accounting effects, and certain foreign exchange impacts on the group's tax charge for the period	**4,235**	1,788	522	1,184	3,162
Adjusted for the impact of US tax reform	**—**	—	121	(859)	—
Taxation on an underlying RC basis	**(743)**	(5,596)	(7,986)	(3,812)	(212)
Adjusted for the impact of the reduction in the rate of the UK North Sea supplementary charge	**—**	—	—	—	434
Adjusted taxation	**(743)**	(5,596)	(7,986)	(3,812)	(646)

Effective tax rate

					%
	2020	2019	2018	2017	2016
ETR on profit or loss for the year	**17**	49	43	52	107
Adjusted for inventory holding gains and losses	**(1)**	2	(1)	3	(31)
ETR on RC profit or loss	**16**	51	42	55	76
Adjusted for non-operating items and fair value accounting effects, and certain foreign exchange impacts on the group's tax charge for the period	**(30)**	(15)	(5)	(9)	(69)
Adjusted for the impact of US tax reform	**—**	—	1	(8)	—
Underlying ETR	**(14)**	36	38	38	7
Adjusted for the impact of the reduction in the rate of the UK North Sea supplementary charge	**—**	—	—	—	16
Adjusted ETR	**(14)**	36	38	38	23

Return on average capital employed (ROACE)

					$ million
	2020	2019	2018	2017	2016
Profit (loss) for the year attributable to bp shareholders	**(20,305)**	4,026	9,383	3,389	115
Inventory holding (gains) losses, net of tax	**2,201**	(511)	603	(628)	(1,114)
Non-operating items and fair value accounting effects, net of tax	**12,414**	6,475	2,737	3,405	3,584
Underlying RC profit	**(5,690)**	9,990	12,723	6,166	2,585
Interest expense, net of tax[a]	**1,402**	1,744	1,583	924	635
Non-controlling interests (NCI)	**(424)**	164	195	79	57
Underlying RC profit attributable to bp shareholders and NCI, excluding interest expense net of tax	**(4,712)**	11,898	14,501	7,169	3,277
Total equity	**85,568**	100,708	101,548	100,404	96,843
Finance debt	**72,664**	67,724	65,132	62,574	57,665
Capital employed (2020 average $163,332 million)	**158,232**	168,432	166,680	162,978	154,508
Less: Goodwill	**12,480**	11,868	12,204	11,551	11,194
Cash and cash equivalents	**31,111**	22,472	22,468	25,586	23,484
	114,641	134,092	132,008	125,841	119,830
Average capital employed excluding goodwill and cash and cash equivalents	**124,367**	133,050	128,925	122,836	116,333
ROACE	**(3.8)%**	8.9 %	11.2 %	5.8 %	2.8 %

[a] Calculated on a post-tax basis (for 2017 and earlier interest expense was net of notional tax at an assumed 35%).

Readily marketable inventory (RMI)

Readily marketable inventory (RMI) is oil and oil products inventory held and price risk-managed by bp's integrated supply and trading function (IST) which could be sold to generate funds if required. Details of RMI balances and a reconciliation to GAAP information is set out below. Further information on RMI, RMI at fair value, paid-up RMI and unpaid RMI is provided on page 345.

At 31 December		$ million
	2020	2019
RMI at fair value	**6,528**	6,837
Paid-up RMI	**3,365**	3,217

Reconciliation of non-GAAP information

At 31 December		$ million
	2020	2019
Reconciliation of total inventory to paid-up RMI		
Inventories as reported on the group balance sheet	**16,873**	20,880
Less: (a) inventories which are not oil and oil products and (b) oil and oil product inventories which are not risk-managed by IST	**(10,810)**	(14,280)
RMI on IFRS basis	**6,063**	6,600
Plus: difference between RMI at fair value and RMI on an IFRS basis	**465**	237
RMI at fair value	**6,528**	6,837
Less: unpaid RMI at fair value	**(3,163)**	(3,620)
Paid-up RMI	**3,365**	3,217

The Directors' report on pages 71-102, 105 (in respect of the remuneration committee report shown in grey only), 127-128, 231-258 and 301-349 was approved by the board and signed on its behalf by Ben J. S. Mathews, company secretary on 22 March 2021.

BP p.l.c.
Registered in England and Wales No. 102498

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)

/s/ Ben J. S. Mathews
Company secretary
22 March 2021

Cross reference to Form 20-F

Information about this report

This document constitutes the Annual Report and Accounts in accordance with UK requirements and the Annual Report on Form 20-F in accordance with the US Securities Exchange Act of 1934, for BP p.l.c. for the year ended 31 December 2020. A cross reference to Form 20-F requirements is included on page 351.

This document contains the Strategic report on the inside front cover and pages 1-70 and the Directors' report on pages 71-102, 105 (in part only), 127-128, 231-258 and 301-349. The Strategic report and the Directors' report together include the management report required by DTR 4.1 of the UK Financial Conduct Authority's Disclosure Guidance and Transparency Rules. The Directors' remuneration report is on pages 103-126. The consolidated financial statements of the group are on pages 129-230 and the corresponding reports of the auditor are on pages 130-154. The parent company financial statements of BP p.l.c. are on pages 259-300.

The Directors' statements (comprising the Statement of directors' responsibilities; Risk management and internal control; Longer-term viability; Going concern; and Fair, balanced and understandable), the independent auditor's report on the annual report and accounts to the members of BP p.l.c., the parent company financial statements of BP p.l.c. and corresponding auditor's report and a non-GAAP measure of operating cash flow excluding Gulf of Mexico oil spill payments★ in the tables on pages 41, 43 and 46 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

bp Annual Report and Form 20-F 2020 may be downloaded from *bp.com/annualreport*. No material on the bp website, other than the items identified as bp *Annual Report* and *Form 20-F 2020*, forms any part of this document. References in this document to other documents on the bp website, such as *bp Energy Outlook*, *bp Sustainability Report*, *bp Statistical Review* of *World Energy* and *bp Technology Outlook* are included as an aid to their location and are not incorporated by reference into this document.

BP p.l.c. is the parent company of the bp group of companies. The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001. Where we refer to the company, we mean BP p.l.c. The company and each of its subsidiaries★ are separate legal entities. Unless otherwise stated or the context otherwise requires, the term "BP" or "bp" and terms such as "we", "us" and "our" are used in this report for convenience to refer to one or more of the members of the bp group instead of identifying a particular entity or entities. Information in this document reflects 100% of the assets and operations of the company and its subsidiaries that were consolidated at the date or for the periods indicated, including non-controlling interests.

The company's primary share listing is the London Stock Exchange. In the US, the company's securities are traded on the New York Stock Exchange (NYSE) in the form of ADSs (see page 332 for more details) and in Germany in the form of a global depositary certificate representing bp ordinary shares traded on the Frankfurt, Hamburg and Dusseldorf Stock Exchanges.

The term 'shareholder' in this report means, unless the context otherwise requires, investors in the equity capital of BP p.l.c., both direct and indirect. As the company's shares, in the form of ADSs, are listed on the NYSE, an Annual Report on Form 20-F is filed with the SEC. Ordinary shares are ordinary fully paid shares in BP p.l.c. of 25 cents each. Preference shares are cumulative first preference shares and cumulative second preference shares in BP p.l.c. of £1 each.

Registered office and our worldwide headquarters:	**Our agent in the US:**
BP p.l.c.	**BP America Inc.**
1 St James's Square	501 Westlake Park Boulevard
London SW1Y 4PD	Houston, Texas 77079
UK	US
Tel +44 (0)20 7496 4000	Tel +1 281 366 2000

Registered in England and Wales No. 102498.
London Stock Exchange symbol 'BP.'

Exhibits

The following documents are filed in the Securities and Exchange Commission (SEC) EDGAR system, as part of this Annual Report on Form 20-F, and can be viewed on the SEC's website.

Exhibit 1	Memorandum and Articles of Association of BP p.l.c.***†
Exhibit 2	Description of rights of each class of securities registered under Section 12 of the Securities Exchange Act of 1934†
Exhibit 4.1	The BP Executive Directors' Incentive Plan**†
Exhibit 4.4	Director's Service Agreement for B Looney****†
Exhibit 4.7	Director's Service Contract for M Auchincloss†
Exhibit 4.10	The BP Share Award Plan 2015***†
Exhibit 8	Subsidiaries (included as Note 37 to the Financial Statements)
Exhibit 11	Code of Ethics*†
Exhibit 12	Rule 13a – 14(a) Certifications†
Exhibit 13	Rule 13a – 14(b) Certifications#†
Exhibit 15.1	Consent of DeGolyer and MacNaughton†
Exhibit 15.2	Report of DeGolyer and MacNaughton†
Exhibit 15.3	Consent of Netherland, Sewell & Associates†
Exhibit 15.4	Report of Netherland, Sewell & Associates†
Exhibit 15.5	Consent Decree***†
Exhibit 15.6	Gulf states Settlement Agreement***†
Exhibit 15.7	Consent of Deloitte LLP†
Exhibit 15.8	Consent of Ernst & Young LLC regarding opinion in Exhibit 99.1†
Exhibit 99.1	Consolidated financial statements of Rosneft Oil Company as at and for the years ended 31 December 2020 (unaudited) and 2019†
Exhibit 99.2	Consolidated financial statements of Rosneft Oil Company as at and for the years ended 31 December 2018 (unaudited) and 2017 (unaudited)†
Exhibit 101	Inline XBRL data files
Exhibit 104	Cover page interactive data file (formatted as Inline XBRL and contained in Exhibit 101)

* Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2009.

** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2014.

*** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2015.

**** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2019.

\# Furnished only.

† Included only in the annual report filed in the Securities and Exchange Commission EDGAR system.

The total amount of long-term securities of BP p.l.c. and its subsidiaries under any one instrument does not exceed 10% of their total assets on a consolidated basis.

The company agrees to furnish copies of any or all such instruments to the SEC on request.

Paper: Nautilus Super White is a premium ecological paper. It is made from 100% post-consumer waste recycled paper and is FSC® (Forest Stewardship Council®) certified. The paper also holds the EU Ecolabel certification. The manufacturing mill also holds ISO 14001 environmental certification. Printed in the UK by Pureprint Group.

FSC www.fsc.org RECYCLED Paper made from recycled material FSC® C022913