Consolidated financial statements of the bp group

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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 2021 and of the group's profit for the year then ended.
- The group financial statements have been properly prepared in accordance with United Kingdom adopted international accounting standards and International Financial Reporting Standards (IFRSs) 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.

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

- group and parent company income statements
- group and parent company statements 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 37 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, United Kingdom adopted international accounting standards and IFRSs as issued by the IASB. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom accounting standards (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 35 to the financial statements. We confirm that apart from the matter disclosed below, we have not provided any other non-audit services prohibited by the FRC's Ethical Standard to the group or the parent company.

We have identified one regulatory breach of audit independence rules, which involved Deloitte South Africa providing fraud and ethics hotline services to a bp subsidiary for an annual fee of approximately $1,000. The service included the answering of calls and the reporting of information gathered to management. The service is administrative in nature and there is no analysis or judgement applied to the information that is reported back to management. The impact of the service to this insignificant affiliate was immaterial and inconsequential and accordingly, we identified no specific risks to our independence. Therefore, we have concluded in agreement with the Audit Committee that our objectivity and impartiality has not been impaired, and we believe that a reasonable and informed third party with knowledge of all relevant facts and circumstances would conclude that we are capable of exercising objective and impartial judgement on all matters related to the audit.

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

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3. Summary of our audit approach

Key audit matters	The key audit matters that we identified in the current year were: • potential impact of climate change and the energy transition • impairment of upstream oil and gas property, plant and equipment (PP&E) assets • decommissioning provisions • accounting for complex transactions executed by the trading and shipping (T&S) function to deliver against the wider group strategy and valuation of commodity financial derivatives, where fraud risks may arise in revenue recognition (potentially impacting all financial statement accounts, in particular finance debt) • IT controls relating to financial systems and • management override of controls. This year we identified decommissioning provisions as a key audit matter, given the high level of general inflation, a legal decision in the US that potentially increases the risk of decommissioning costs reverting to the group in respect of prior asset disposals and our ongoing challenge of management's judgement that decommissioning provisions are not required for refineries as their decommissioning date is indeterminate. We have not included a key audit matter in respect of the write-off of exploration and appraisal (E&A) assets this year as there has been no repeat of the $9.9 billion write-off in the prior year. Our ongoing challenge as to whether development of the remaining $4.3 billion of E&A assets is consistent with bp's stated strategy is covered in our climate change key audit matter. We have not included a separate COVID-19 key audit matter again this year as bp now has a track record of identifying and managing the challenges posed by COVID-19 and the areas of our audit significantly impacted by COVID-19 are covered by the other key audit matters in this report. 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 $700 million (2020 $600 million) which was determined based on profit before tax and underlying replacement cost profit before interest and tax. In the prior year we determined materiality based on net assets given the significant losses incurred as a consequence, inter alia, of the COVID-19 pandemic and in particular the low oil and gas prices.
Scoping	Our scope covered 226 consolidation units (cons units). Of these, 174 were full-scope audits and the remaining 52 were subject to specific procedures on certain account balances by component audit teams or the group audit team. These covered 74% of group revenue, 76% of PP&E and 72% of profit before tax. The remaining 630 cons units were subject to other procedures, including performing 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:

- considering 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
- assessing the financing facilities including nature of facilities, repayment terms and covenants
- challenging the assumptions used in the forecast (in particular oil and gas prices, capital expenditure, production levels and debt repayments)
- assessing management's identified potential mitigating actions and the appropriateness of the inclusion of these in the going concern assessment
- testing the clerical accuracy and appropriateness of the model used to prepare the forecasts
- assessing the historical accuracy of forecasts prepared by management
- reperforming management's sensitivity analysis and
- confirming the disclosures made within the financial statements.

Based on our assessment, we concluded that the assumptions used by management were reasonable overall 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.

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The matters described below 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.

5.1 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 2-80 of the Annual Report and Note 1 of the financial statements on page 178. It represents a strategic challenge and a key focus of management. The related risks that we have identified for our audit are as follows: • Forecast assumptions used in assessing the value-in-use of oil and gas PP&E assets within bp's balance sheet for impairment testing, particularly oil and gas price assumptions and their interrelationship with forecast emissions costs, may not appropriately reflect changes in supply and demand due to climate change and the energy transition (see 'impairment of upstream oil and gas PP&E assets' below). • The timing of expected future decommissioning expenditures in respect of oil and gas assets may need to be brought forward with a resulting increase in the present value of the associated liabilities due to the impact of climate change. In addition, provisions for decommissioning and asset retirement obligations of oil and gas PP&E may increase as a result of possible exposure to decommissioning obligations that may revert back to bp in respect of assets transferred to third parties through historical divestments. The risk of possible exposure is enhanced due to the impacts of climate change which have heightened liquidity and financial resilience concerns for many industry participants. Furthermore, provisions for decommissioning 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 curtail their operational lives; (see 'Decommissioning provisions' below). • The recoverability of certain of the group's $4.3 billion total exploration and appraisal (E&A) assets capitalised at 31 December 2021 (2020 $4.1 billion, following $9.9 billion of pre-tax write-offs and impairments recorded during the prior year) are potentially exposed to climate change and the global energy transition risk factors (see Note 14). This is because a greater number of E&A projects may not proceed as a consequence of lower forecast future oil and gas prices, bp's intention to reduce its hydrocarbon production (by around 40% by 2030 relative to 2019 – see page 17), the group's 'no exploration in new countries' commitment, and potentially increased objections from stakeholders to the development of certain projects. The determination of whether and when E&A costs should be written off, impaired, or retained on the balance sheet as E&A assets, remains complex, continues to require significant management judgement and is a higher audit risk for certain E&A projects. • The carrying value of the group's refining assets within PP&E may no longer be recoverable, due to changes in supply and demand which arise as a consequence of 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 in respect of each of its refineries during the year. As a result, impairment tests were performed to assess the recoverability of each of these refineries' carrying value. As disclosed in Note 3 to the accounts on page 200, management has recorded impairment charges of $962 million in the Customers & Products (C&P) segment, which primarily related to their refining assets. • bp's intention to reduce its hydrocarbon production (by around 40% by 2030 relative to 2019) and the group's wider strategy includes potentially disposing of certain high emissions intensity upstream oil assets and others. As a consequence, certain assets may need to be assessed for impairment based on their estimated disposal proceeds from a third party, as opposed to their value-in-use to bp. Management recorded $1.1 billion of pre-tax impairment charges in 2021 for such potential disposals as described in Note 3. There is an audit risk that management judgements taken to determine whether impairment charges are required based on bp's view of whether transactions are likely to proceed or not, and bp's strategic appetite regarding the value of disposal consideration that would be accepted, are not reasonable. • The useful economic lives of the group's 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 179, management concluded that demand for refined products is expected to remain sufficient for the existing refineries to continue operating for the duration of their remaining useful lives and hence no changes to the useful economic lives of its refinery assets were required. • The total goodwill balance at 31 December 2021 is $12.4 billion, of which $7.6 billion relates to upstream oil and gas assets. The carrying values of goodwill may no longer be recoverable and therefore may need to be impaired. For oil production & operations (OP&O), goodwill is allocated to CGUs in aggregate at the segment level and for gas & low carbon energy (G&LCE) goodwill is allocated to the hydrocarbon CGUs within the segment. The most significant assumption in the goodwill impairment tests affected by climate change relates to future oil and gas prices (see 'Impairment of upstream oil and gas PP&E assets' below). Given the level of headroom in the goodwill impairment tests, which is significant for the OP&O segment, but more limited for G&LCE, 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 13 on page 212. The C&P segment has a goodwill balance of $4.7 billion, of which the most significant element is $2.8 billion relating to the Lubricants business. Notwithstanding the expected global transition to electric vehicles which may reduce demand for Lubricants, due to the substantial headroom in the most recent impairment test (as described in Note 13), management has assessed as remote the likelihood that the recoverable amount of goodwill is less than its carrying value. • Climate change-related litigation brought against bp, as disclosed in Note 32 to the financial statements, may lead to an outflow of funds requiring provision in the current year.

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	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** The audit response related to two of the audit risks identified is set out under the key audit matters for 'Impairment of upstream oil and gas PP&E assets' on pages 151-153 and 'Decommissioning provisions' on pages 154-155. Other procedures are as follows: In respect of the recoverability of E&A assets capitalised at 31 December 2021: • We obtained an understanding of the group's E&A write-off and impairment assessment processes and tested management's key internal controls, including the controls that assess climate change related risks. • We challenged and evaluated 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 for 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 external press releases, meeting minutes, licence documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms. • 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 strategy and in particular its net zero carbon commitments, bp's intention to reduce its hydrocarbon production (by around 40% by 2030 relative to 2019), and the group's 'no exploration in new countries' commitment. We challenged the results of the impairment testing of PP&E refining assets by considering internal and external market studies of future supply and demand and conducting sensitivity analysis. In relation to refinery impairment tests, we assessed the valuation methodology, tested the integrity and mechanical accuracy of the impairment models and assessed the appropriateness of key assumptions and inputs. We also evaluated management's ability to forecast future cash flows and margins by comparing actual results to historical forecasts and tested management's internal controls over the impairment tests. We challenged management's analysis that identified the specific assets that are likely to be disposed of by the group as part of its strategy. Where relevant, we challenged bp's asset impairment assessments based on their estimated disposal proceeds and whether transactions are judged likely to proceed or not. We obtained evidence of any negotiations with third parties and carefully considered the group's strategic intent in this context. We challenged management's assertion that no changes are required to the assessed useful economic lives of refining assets as a consequence of 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 the C&P segment. In particular, we considered the forecasts as set out in the IEA World Energy Outlook 2021 which shows 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 the Sustainable Development Scenario (SDS) consistent with the Paris 'well below 2°C goal'. In its definition of the SDS, the IEA states that with some level of net negative emissions after 2070, the temperature rise could be reduced to 1.5°C in 2100. We performed procedures to satisfy ourselves that, other than future oil and gas price assumptions, there were no other assumptions in management's oil and gas goodwill impairment tests to which reasonably possible changes due to the energy transition and other climate change factors could cause goodwill to be materially misstated. We obtained evidence which supported management's conclusion that goodwill relating to the C&P segment activities is not impaired due to climate change or other factors. 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 executive vice president, legal 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.

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	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.
Key observations	Key observations in relation to oil and gas price assumptions used in oil and gas PP&E asset impairment tests, and the impact of climate change on decommissioning provisions are set out in the relevant key audit matter below. We concluded that the key E&A assessments had been appropriately determined and the judgements management had made were appropriately supported. We did not identify any additional impairments or write-offs 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 in light of climate change and the energy transition. We are satisfied: • with the results of our procedures relating to the carrying value of refining assets and that the impairments recorded are reasonable. • that management's planned disposal related asset impairment assessments are reasonable; and we did not identify any additional material impairments • with the results of our procedures relating to the assessment of the useful economic lives of refining assets and therefore depreciation charges, based on the market studies we read • with the sensitivity analysis disclosures around the energy transition and other climate change factors performed in respect of the goodwill balances; and that the group's goodwill balances are not materially misstated • with management's assertion that no provision should currently be made in respect of climate change litigation. Based on the audit evidence obtained both from internal and external legal counsel, we concluded that management's disclosure of the contingent liabilities in respect of these matters is appropriate and • 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. Whilst many of bp's oil and gas properties and refining assets are long term in nature, by 2050, the remaining carrying value of assets currently being depreciated will be immaterial, this date being the target set by the majority of governments with 'net zero' emissions targets and also by bp, being Aim 1 of the 'Getting to net zero' strategy set out on page 51. At current rates of depreciation, depletion and amortisation (DD&A), the average remaining depreciable life of the upstream oil and gas PP&E (within the OP&O and G&LCE segments) is just seven years and the refining assets (within the C&P segment) is fifteen years.

5.2 Impairment of upstream oil and gas property, plant and equipment (PP&E) assets	
Key audit matter description	The group balance sheet at 31 December 2021 includes PP&E of $113 billion (2020 $115 billion), of which $74 billion (2020 $74 billion) is oil and gas properties within the OP&O ($47 billion) and G&LCE ($27 billion) segments. Management's best estimate of oil and gas price assumptions for value-in-use impairment tests were revised during 2021 as set out in Note 1 on page 178. The upward revisions to Brent oil assumptions up to 2030, and Henry Hub gas assumptions for 2022, compared to the prior year reflect expected near-term supply constraints. Brent oil assumptions post 2030 were revised downwards compared to the prior year, as bp expects an acceleration in the pace of transition to a low carbon economy. Aside from 2022, Henry Hub gas assumptions are unchanged from the prior year. Given the significance of the price assumption revisions during 2021, alongside certain CGU specific new indicators, management tested most oil and gas CGUs for impairment and/or impairment reversal during the year. Management recorded $4.8 billion (2020 $0.1 billion) of pre-tax oil and gas CGU impairment reversals, in large part due to the oil and gas price upwards revisions detailed above, and $2.4 billion of pre-tax oil and gas CGU impairment charges (2020 $12.9 billion). Further information has been provided in Note 1 on page 184 and Note 3 on page 198. 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 OP&O and G&LCE segments and are inherently uncertain. The estimation of future prices is subject to increased uncertainty given climate change, the global energy transition and COVID-19. There is a risk that management do not forecast reasonable 'best estimate' oil and gas price forecasts when assessing CGUs for impairment and/or reversal, leading to material misstatements. These price assumptions are highly judgmental and are pervasive inputs to bp's oil and gas CGU valuations, such that any misstatements would also aggregate. There is also a risk that management's oil and gas price related disclosures are not reasonable. Aside from 2022 where oil and gas prices reflect near-term expected market conditions, the group's oil and gas price assumptions for value-in use impairment assessments are aligned with bp's investment appraisal assumptions, except that potential future emissions costs that could be borne by bp are included in investment appraisals as bp costs without assuming incremental revenue. As described in Note 1 on page 178, emissions costs forecasts interrelate with bp's oil and gas prices, because bp's price assumptions for value-in-use estimates represent 'net producer prices', i.e., net of any further emissions costs that may be enacted in the future. There is a risk management's judgement is not reasonable, that the potential impact of such further emissions costs being borne by producers including bp is not expected to have a material impact on the group's oil and gas CGU carrying values as costs would effectively be borne by oil and gas end users via overall higher commodity prices. • **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 bp's oil and gas CGU valuations, 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 and/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 OP&O and G&LCE segments. We identified certain individual CGUs with a total carrying value of $33 billion (2020 $32 billion) which we determined would be most at risk of material impairment charges (and/or impairment reversals for CGUs with a combined $25 billion carrying value within this population) as a result of a plausible change in the oil and gas price assumptions. We identified that a subset of these CGUs were also individually materially sensitive to the discount rate assumption. Accordingly, we identified these as significant audit risks. We also identified CGUs with a further $12 billion (2020 $16 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 by a plausible change in some or all of the key assumptions. No impairment reversals are available for these CGUs. Further information regarding these sensitivities is given in Note 1 on page 186. Impairment and/or reversal assessments of upstream oil and gas PP&E assets remain a key audit matter because recoverable values are reliant on forecasts that are inherently judgemental and complex for management to estimate, and the magnitude of the potential misstatement risk is material to the group.

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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 and/or reversal 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 and the energy transition. The 2015 COP 21 Paris Agreement goals 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' was reaffirmed at COP 26 in Glasgow during November 2021. Nevertheless we understand that certain stakeholders are focussed increasingly on the 'no greater than 1.5°C' ambition element of the Paris Agreement.
- We specifically analysed third party forecasts stated, or interpreted by us, as being consistent with scenarios achieving the Paris 'well below 2°C goal' and/or '1.5°C ambition' and considered whether they presented contradictory audit evidence.
- We challenged management's judgement, described in Note 1 on page 179, that the potential impact of further emission costs being borne by producers including bp is not expected to have a material impact on the group's oil and gas CGU carrying values. We inquired of certain third party forecasters included in our reasonable range and reviewed their forecast price reports, to understand whether their oil and gas prices are forecast on a 'net producer prices' basis, (i.e. net of potential future emissions costs that are assumed to be borne by oil and gas end users), consistent with the basis of bp's value-in-use price assumptions.
- We assessed management's disclosures in Notes 1 and 3, including the sensitivity of forecast revenue cash inflows to lower oil and gas prices and how climate change and the energy transition, potential future emissions costs and/or reduced demand scenarios may impact bp to a greater extent than currently anticipated in the group's value-in-use estimates for oil and gas CGUs.

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 3 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 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 and assessed management's CGU determinations, and considered whether there was any contradictory evidence present.
- We assessed whether 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 and assessed 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.
- We assessed whether management's forecasts are consistent overall with bp's strategy, including the group's expectation to reduce its hydrocarbon production (by around 40% by 2030 relative to 2019). We observed they are not consistent in aggregate because bp expects to dispose of certain non-core assets in future periods (see 'Potential impact of climate change and the energy transition' above).
- 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.

Key observations	Oil and gas prices
	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 determined that bp's 'best estimate' assumptions are reasonable when compared against a range of third party forecasts and peer information that we identified as being appropriate for this purpose. In forming this view, we included each forecaster's 'base case', 'central case' or 'most likely' estimate.
	We further observed that, as well as publishing a 'base case', 'central case' or 'most likely' estimate, certain third party price forecasters (including the IEA; and the WBCSD Catalogue pre-publication version as of January 2022) published other price forecasts including some that were stated as, or were interpreted by us as being, Paris 'well below 2°C goal' or Paris '1.5°C ambition' scenarios. We observed that none of those third party forecasters described their 'Paris consistent' scenarios as their 'base case', 'central case' or 'most likely' estimate.
	Management notes on page 178 that they consider their 'best estimate' prices to be in line with a range of transition paths consistent with the Paris climate goal of limiting global warming to well below 2°C as well as the ambition to limit global warming to no greater than 1.5°C. We observed that for oil, whilst being within the lower half of our range of 'best estimate' forecasts described above, bp's price assumptions were overall within the higher half of our range of Paris 'well below 2°C goal' and Paris '1.5°C ambition' scenarios. For gas, whilst being within the lower half of our range of 'best estimate' forecasts as described above, bp's price assumptions were towards the mid-point of our range of Paris 'well below 2°C goal' and Paris '1.5°C ambition' scenarios. We also noted certain other reputable third party sources that set out or implied even higher prices under both Paris 'well below 2°C goal' and Paris '1.5°C ambition' scenarios and that there are a very wide range of price forecasts, reflecting the fact that there are an infinite number of 'Paris consistent' pathways. Accordingly, we consider management's statement as set out above to be reasonable.
	By inquiry and analysis, we confirmed that the third party oil and gas price forecasts used to develop our independent range are on a net producer price basis. Accordingly, we are satisfied management's judgement is reasonable that the potential impact of further emission costs being borne by bp is not expected to have a material impact on the group's oil and gas CGU carrying values.
	We reviewed the disclosures included in Note 1 to the accounts in respect of oil and gas price assumptions, including the sensitivity analysis presented therein. We observed that management's downside sensitivity, in which oil and gas prices are 20% lower than the 'best estimate' in all future periods, is near the mid-point of both a range of third party Paris 'well below 2°C goal' and Paris '1.5°C ambition' scenarios for oil price forecasts. For gas, management's downside sensitivity is within the lower half of both a range of third party Paris 'well below 2°C goal' and Paris '1.5°C ambition' scenarios.
	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 for oil and gas assets, 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 and reversal testing.
	Reserves and resources estimates
	We found that the production forecasts used in the oil and gas CGU valuations that we tested were reasonable and appropriately risked where applicable, for the purposes of management's impairment and reversal tests.

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5.3 Decommissioning provisions	
Key audit matter description	A decommissioning provision of $16.4 billion has been recognised in the Consolidated Financial Statements at 31 December 2021. The estimation of decommissioning provisions is a highly judgemental area as it involves a number of key estimates related to the cost and timing of decommissioning, as well as inflation and discount rate. Given management expects hydrocarbon production to be around 40% lower by 2030 relative to 2019 as stated on page 17, consistency of that expectation with the timing of decommissioning expenditure and underlying cost assumptions remains a key consideration. The estimated undiscounted cost of its obligations and the timing of future payment are set out in Note 1 on page 191. Economic factors, future activities and the legislative environments that bp operates in are used to inform cost estimates, whereas the timing of decommissioning activities is dependent on cessation of production (CoP) dates, which are sensitive to changes in bp's price forecasts as price estimates determine economic cut off of oil and gas reserve estimates. The inflation rate used in bp's decommissioning provision calculations has remained unchanged during 2021 at 1.5%. The impact of inflation on the forecast cost assumptions is an area of specific focus given the significant and sustained inflationary increases experienced globally since early 2021. In the second quarter of 2021 bp reduced its discount rate used for calculating its decommissioning provisions from 2.5% to 2.0% due to ongoing challenging macroeconomic conditions decreasing US treasury bond rates. Additionally, bp is potentially exposed to decommissioning obligations that could revert back to bp in respect of historical divestments to third parties. Judgement is required to assess the potential risk of reversion and if applicable, the estimated exposure, for each historically divested asset. The risk of possible exposure was enhanced due to the impacts of the COVID-19 pandemic and climate change, which have heightened liquidity and financial resilience concerns for many industry participants. The risk has further increased following a US legal judgement in the year which required a specific provision and increased the likelihood of decommissioning liabilities reverting to former owners as part of a bankruptcy proceeding. Provisions for decommissioning 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 curtail their operational lives. As disclosed in Note 1 on page 191 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. Management has conducted analysis which supports a conclusion that demand for refined products is expected to remain strong in areas served by its existing refineries. In addition, management is developing plans for the production of alternative low carbon and sustainable fuels at each of the existing refinery sites remaining in the portfolio. 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. We determined this to be a key audit matter given the increased risk identified in the year and the audit resources directed to it, including by senior members of the team.
How the scope of our audit responded to the key audit matter	We obtained an understanding of the group's decommissioning estimate and provisioning process and evaluated the effectiveness of the relevant controls. **Cost and timing estimates** • We assessed the completeness and accuracy of the assets subject to decommissioning, including understanding the process to establish whether a legal or constructive obligation existed. • We evaluated changes in key cost assumptions including rig rates, vessel rates, well plug and abandonment duration and non-productive time assumptions. We also assessed the reasonableness of key cost assumptions with reference to internal and appropriate third party data. • We considered the expectation that demand for oil and gas products and related activities will decrease, primarily in response to climate change and energy transition effects pivoting future energy industry investment and development activity towards renewable sources. We challenged management's assessment of the impact this will have on the decommissioning provisions. • We assessed changes in assumptions for the estimated date of decommissioning and ensured that CoP dates used for decommissioning estimation are aligned with CoP assumptions in other areas, including PP&E impairment testing and oil and gas reserve estimation. • We assessed the accuracy of bp's additional disclosure of the estimated undiscounted cost of its obligations and the timing of future decommissioning payments. **Inflation and discount rates** • With the help of our valuation specialists, we evaluated the discount and inflation rate assumptions used, comparing them against latest external market data. • We challenged how management has considered the current high level of inflation in setting 2021 decommissioning cost assumptions. • We tested the decommissioning models, assessing the application of cost, timing, inflation and discount rate assumptions when calculating the final provisions.

	Reversion risk • We obtained an understanding of the group’s decommissioning reversion risk assessment process, noting that the process was enhanced during 2021 in direct response to the increased potential default risk in respect of historical divestments to third parties. • We tested management’s key internal controls within this enhanced process, including those controls over the completeness and accuracy of the previously divested asset data. • We challenged management’s key judgements related to the decommissioning reversion risk and conclusions on whether any additional provision should be recognised or specific contingent liability disclosure made. We assessed the relevant internal and external evidence used in forming this judgement, including the financial health of the counterparty or counterparties in the ownership chain for the divested assets and the existence of any other pertinent factors which could indicate a higher probability of decommissioning obligations reverting to bp. **Potential decommissioning of refinery assets** • We challenged and evaluated 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 current intention to cease these activities. As referenced in the 'Potential impact of climate change and the energy transition' key audit matter in section 5.1 above, we considered internal and external demand forecasts. Furthermore, we read external profitability benchmarking which supported a conclusion that the company's remaining refineries would likely remain operational for longer than many of their regional competitors, in the event of refining capacity reductions. We also met with refinery management to understand the potential alternative use cases under consideration for refineries in the future, which include options for production of low carbon and sustainable fuels.
Key observations	We concluded that that the cost and timing assumptions used in the decommissioning provision calculation were reasonable and the assumptions are appropriately supported by industry data. The disclosure included on page 191 with respect to the estimated undiscounted cost of bp’s decommissioning obligations and the timing of future decommissioning payments are consistent with these conclusions. We concluded that the assumed inflation rate of 1.5% remains reasonable as a long-term inflation rate for decommissioning liabilities. We accept as reasonable that the high level of general inflation experienced in 2021 does not require a change to bp’s long term average inflation assumption. With respect to short term inflation, industry specific benchmarking remains supportive of the reasonableness of the provision cost estimates, with no significant 2021 inflation impact observed. bp’s reduced 2.0% discount rate was within a reasonable range based on latest market data. No material additional decommissioning provisions have been made in respect of historical divestments where bp are exposed to decommissioning reversion risk as a result of the future bankruptcy of the current asset owner. Based on our review and challenge of management’s assessment, we consider this judgement to be reasonable. We also consider the contingent liability disclosure to be reasonable. In respect of the group’s refining assets, taking into consideration both the IEA 2021 demand forecasts and management’s plans for the production of low carbon and sustainable fuels, we are satisfied that it is not currently possible for management to estimate reliably a settlement date for any decommissioning obligations prior to a decision being made to cease refining operations. Accordingly, we have not identified any triggers that would require a decommissioning provision to be recorded.

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5.4 Accounting for complex transactions executed by the trading and shipping (T&S) function to deliver against the wider group strategy and valuation of commodity financial derivatives, where fraud risks may arise in revenue recognition (potentially impacting all financial statement accounts, in particular finance debt)

Key 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. Amongst other things, to achieve bp's 'net-zero' ambition and to support the group strategy, T&S as a function is increasingly focused on executing long term renewable power offtake/supply contracts in existing and new markets whilst providing solutions to bp's customer through offering eco-friendly hydro-carbons. The nature of these transactions requires significant audit effort to be directed towards challenging management's adopted accounting treatment and/or valuation estimates. Throughout the year, we have kept our risk assessment updated by undertaking a review of portfolio composition. This process aided a deeper understanding of the impact of commodity price volatility, demand destruction resulting from the COVID-19 pandemic and the changing structure of the markets, including the impact of the transition to renewables across all regions where bp operates, allowing us to focus our audit effort to areas of highest risk. **Accounting for structured commodity transactions (SCTs)**: 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 • reference 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 initially involves significant judgment, as a feature of these transactions is that they often include multiple elements that will have a material impact on the presentation and disclosure in the financial statements and on key performance measures, including in particular the classification of liabilities as finance debt. Accordingly, we have identified a significant audit risk around the accounting for SCTs that have a quantitative impact of $300 million or higher on balances that affect group KPIs. Although we have reviewed several new SCTs entered into during the year, we have not identified any new types of SCT structures which we assess to be a significant risk. **Valuation of commodity financial derivatives:** Commodity markets remained volatile during the year on the back of continuing demand uncertainty as a result of the pandemic and supply disruptions following geo-political tensions. In response to the volatility observed, we focused our audit efforts across valuation of all commodity derivatives and designed procedures to specifically test for management bias. 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 2021, the group's total financial assets and liabilities measured at fair value were $12.8 billion (2020 $12.7 billion) and $13.9 billion (2020 $8.4 billion), of which level 3 derivative financial assets were $5.5 billion (2020 $6.4 billion) and level 3 derivative financial liabilities were $3.9 billion (2020 $5.3 billion).

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<table>
<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 discussions with management and reading transaction documents and executed agreements.
• Performed a detailed accounting analysis for a sample of SCTs involving significant day one profits, offtake arrangements and/or significant contractual commitments. We confirmed that any day one profits were appropriately deferred.
• Selected a sample of existing working capital arrangements and financing structures to ensure that associated trading activity was in compliance with boundary conditions and the conclusions reached remained in compliance with relevant accounting standards.
For SCTs which were identified during the prior years and that continue through 2021, we have refreshed our assessment in 2021 taking account of any amendments to the contracts. We assessed the conclusions reached previously remain appropriate and in accordance with relevant accounting standards.
To assess the appropriateness of the accounting treatment of SCTs, we embedded technical accounting specialists within the audit team.
Valuation of commodity financial derivatives:
In response to the increased volatility observed in the market and to test for management bias, we altered the extent and timing of our procedures by performing an independent valuation of a sample of distinct Level 2 derivatives at 30 June, 30 September and 31 December, and on a sample of distinct Level 3 derivatives at 30 September and 31 December. In addition, we have focused our testing on price inputs where bp has substantial exposure to illiquid (Level 3) or long dated (Level 2) curves.
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 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
◦ 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.
</td></tr>
<tr><td>Key observations</td><td>
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 commodity derivatives 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.
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5.5 IT controls relating to financial systems	
Key audit matter description	The group's financial systems environment is complex, with 116 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. **User Access Management:** In 2018 to 2020 we identified a number of deficiencies relating to user access management, across the group's IT environment (together 'access deficiencies'). Management implemented a remediation and mitigation programme throughout 2019 and 2020 which addressed the deficiencies identified in the applications and in 2021 management completed the programme on the infrastructure layers. In 2021, to the extent the controls had not been remediated, management designed and tested mitigating controls for the period prior to the successful remediation of each control. The remaining access deficiencies during the course of the year increase the risk that individuals across bp had inappropriate access during the period. This results in an increased risk that data, reports and automated controls from and within the affected systems are not reliable. These deficiencies impact all components within the scope of our group audit. 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	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 access deficiencies our IT specialists 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 organisations and • determine the impact that utilising 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.
Key observations	Our testing confirmed that the remediated controls were implemented effectively prior to year-end. For the period the controls were ineffective management identified and operated appropriate mitigating controls. In addition, our independent testing to demonstrate whether the access management deficiencies were exploited during the year, did not identify instances of inappropriate access usage. Accordingly, we were satisfied with the results of the remediation by year end and the mitigation for the period the controls were not operating meaning 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.

5.6 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. 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 incentives which could exist in light of bp's share buyback commitments communicated to its shareholders. Our considerations included the potential for: • inappropriate accounting estimates and judgements • the posting of fictitious or fraudulent journal entries or • inappropriate accounting for significant unusual transactions arising from changes to the business. During all our previous audits since 2018, 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 was impacted by the IT control issues. During the early months of 2021, some of the IT control issues remained. 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.

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How the scope of our audit responded to the key audit matter	We tested management's remediation of the journal controls, but as a result of the remaining IT issues impacting the earlier months of the year, we also tested the mitigating controls that management identified, similar to the prior year, to respond 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 for testing journal entries and other adjustments made at the end of a reporting period or otherwise having characteristics associated with common fraud schemes. 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 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 156-157.
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 the mitigating controls indicated that they were operating effectively. We evaluated the design of the controls implemented in 2021 to remediate the deficiencies and will test the operating effectiveness of these as part of our 2022 audit. 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.

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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 $700 million for the current year. In 2020, we used a materiality of $600 million. The increase is due to bp’s improved financial performance in 2021.	Materiality has been set at $1,000 million for the current year (2020 $900 million).
Basis for determining materiality	Due to the improved results in 2021, following 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 concluded that it was appropriate to change back to profit measures to determine our materiality. Accordingly, we changed our chosen metric from net assets in 2020 to profit before tax and underlying replacement cost profit before interest and tax in 2021. Materiality was determined to be $700 million, which is 4.6% of profit before tax, 3.1% of underlying replacement cost profit before tax and 0.77% of net assets. In 2020, we determined materiality to be $600 million, 0.73% of net assets.	We determined materiality for our audit of the standalone parent using 1% (2020 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. Profit before tax is the benchmark ordinarily considered by us when auditing listed entities. It provides comparability against 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. This resulted in us selecting profit before tax and underlying replacement cost before interest and tax as the most appropriate benchmarks. 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 and therefore is considered to be an appropriate benchmark. 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 for the prior 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 nontrading 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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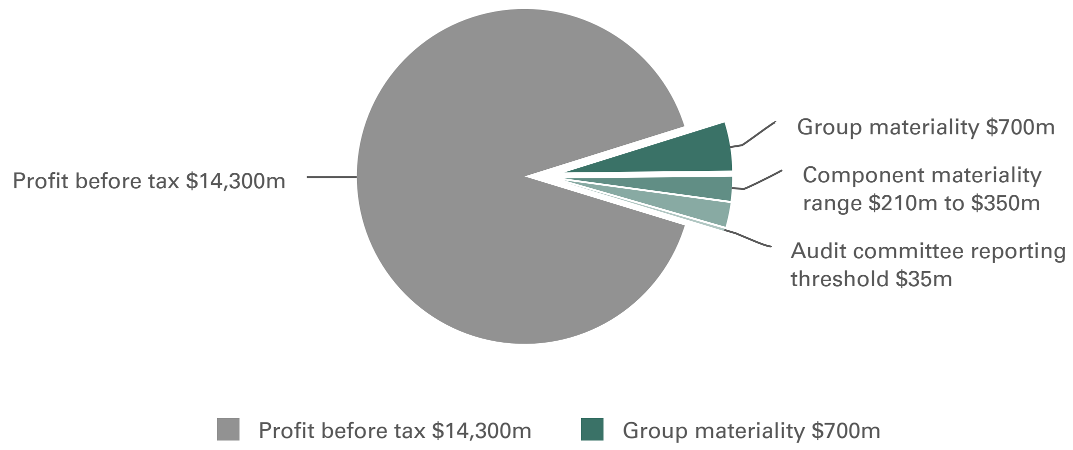

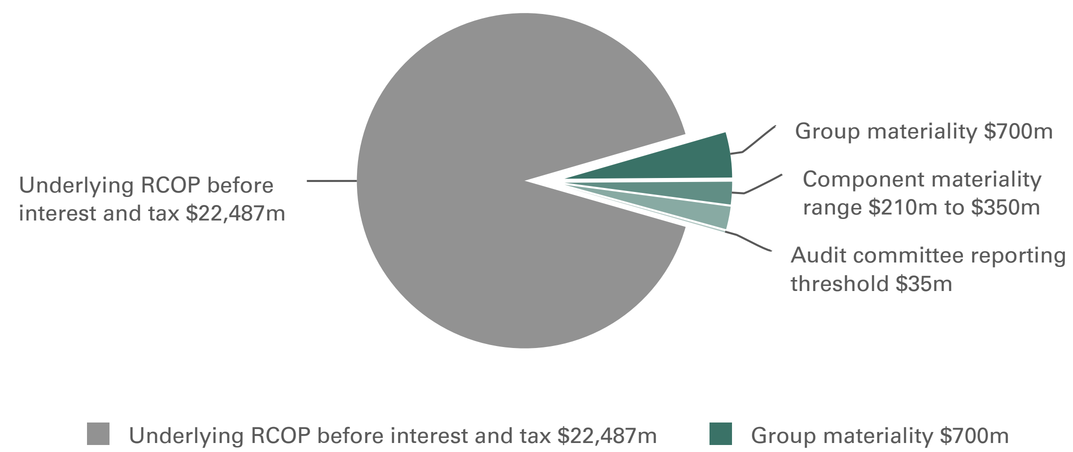

6.2 Performance materiality

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 financial statements	Parent company financial statements
Performance materiality	Group performance materiality was set at 65% of group materiality for the 2021 audit (2020 60%)	Parent company performance materiality was set at 65% of parent company materiality for the 2021 audit (2020 60%).
Basis and rationale for determining performance materiality	Given the significant improvement in results in 2021 we increased our percentage compared with that of our 2020 audit to reflect the improved results, 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 $35 million (2020 $30 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 850 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 profit before tax, or PP&E, including consideration of the financial significance of specific account balances or transactions.
- The significance of specific risks relating to an operating unit, history of unusual or complex transactions, identification of significant audit issues or the potential for, or a history of, material misstatements.

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- 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 2020 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 174 reporting cons units (2020 173) which were selected based on their size or risk characteristics. There are additional cons units in respect of the Lubricants business which have been scoped in during the current year to ensure an appropriate audit coverage of revenue, following the change in accounting policy in respect of the integrated books in the T&S function. Certain cons units have fallen out of scope due to disposals, asset impairments and non-recurring one off transactions which were in scope in the prior year. Our full-scope audits are in the UK, US, Australia, Azerbaijan, Germany and Singapore. One of the full-scope cons units includes the investment in Rosneft, a material associate not controlled by bp.

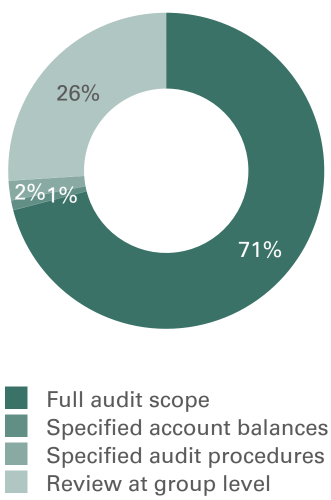
In addition, component teams performed audit procedures on specified account balances in 32 cons units (2020 62) also covering Angola, Alaska, Trinidad & Tobago, Mauritania & Senegal, and Canada. The group engagement team performed audit procedures on specified account balances to component materiality, with certain additional specific procedures performed by component teams, covering an additional 20 cons units (2020 42).

The remaining cons units are not significant individually and include many small, low risk components and balances. On average, they each represent 0.04% of group revenue (2020 0.03%), 0.03% of property, plant and equipment (2020 0.03%) and 0.03% of profit before tax (2020 0.03%).

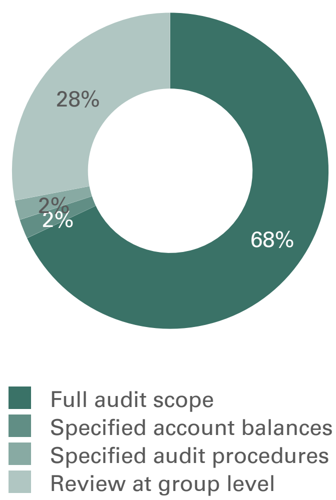
In our assessment of the residual balances not covered by the above procedures, we have considered in particular the risk that there could be a material misstatement within the large number of geographically dispersed businesses, in particular within the C&P segment. This assessment included use of our 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. This year we have also included the ‘Profit before tax’ audit coverage.

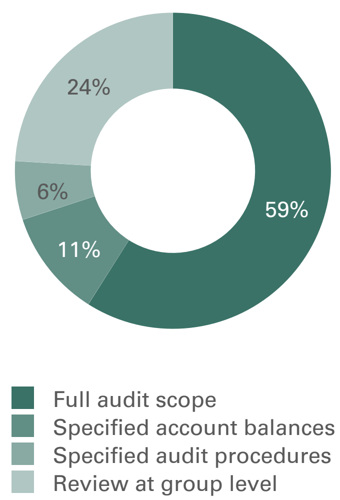
Revenue



Profit before tax



Property, plant & equipment



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, 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 116 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 at our component and other key 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, virtual 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 three days in June and July 2021 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.

8. Other information

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

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.

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 course of 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 this gives rise to a material misstatement in the financial statements themselves. 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.

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

Irregularities, including fraud, are instances of non-compliance with laws and regulations. We design procedures in line with our responsibilities, outlined above, to detect material misstatements in respect of irregularities, including fraud. The extent to which our procedures are capable of detecting irregularities, including fraud is detailed below.

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 specialists who advised the engagement team of fraud schemes that had arisen in similar sectors and industries and they participated in the initial fraud risk assessment discussions.

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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, United Kingdom adopted international accounting standards, 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 and environmental regulations.

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 non-compliance with laws and regulations. We did identify two key audit matters relating to fraud risks, as described above, being the accounting for SCTs and Level 3 instruments within 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, 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 legal counsel concerning actual and potential litigation and claims
- obtained confirmations from external legal counsel concerning open litigation and claims
- performing analytical procedures to identify any unusual or unexpected relationships that may indicate risks of material misstatement due to fraud and
- reading minutes of meetings of those charged with governance, reviewing internal audit reports and reviewing correspondence with HMRC and the IRS.

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.
- 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 143
- 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 143
- the directors' statement on fair, balanced and understandable set out on page 143
- the board's confirmation that it has carried out a robust assessment of the emerging and principal risks set out on page 73
- the section of the annual report that describes the review of effectiveness of risk management and internal control systems set out on page 142 and
- the section describing the work of the audit committee set out on pages 107-113.

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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.

15. Other matters which we are required to address

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 12 May 2021, 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 2022 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 4 years, covering the years ending 31 December 2018 to 31 December 2021.

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.

In due course, as required by the Financial Conduct Authority (FCA) Disclosure Guidance and Transparency Rule (DTR) 4.1.14R, these financial statements will form part of the ESEF-prepared Annual Financial Report filed on the National Storage Mechanism of the UK FCA in accordance with the ESEF Regulatory Technical Standard ('ESEF RTS'). This auditor's report provides no assurance over whether the annual financial report has been prepared using the single electronic format specified in the ESEF RTS.

Douglas J King FCA (Senior statutory auditor)
For and on behalf of Deloitte LLP
Statutory Auditor
London, United Kingdom
18 March 2022

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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 at 31 December 2021 and 2020, 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 2021, 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 at 31 December 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended 31 December 2021,in conformity with United Kingdom adopted international accounting standards and International Financial Reporting Standards (IFRSs) as adopted by the European Union and IFRSs 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 2021, based on criteria established in the *UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting* relating to internal control over financial reporting and our report dated 18 March 2022 expressed an unqualified opinion on the group's internal control over financial reporting.

Change in accounting principle

As discussed in Note 1 to the financial statements, the Company has changed its accounting policy related to the presentation of revenues and purchases relating to physically settled derivative contracts.

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. Impairment of upstream oil and gas property, plant and equipment (PP&E) assets – Notes 1, 3 and 11 to the financial statements

Critical Audit Matter Description

The group balance sheet at 31 December 2021 includes PP&E of $113 billion, of which $74 billion is oil and gas properties within the OP&O ($47 billion) and G&LCE ($32 billion) segments.

Management's 'best estimate' of oil and gas price assumptions for value-in-use impairment tests were revised during 2021 as set out in Note 1 on page 178. The upward revisions to Brent oil assumptions up to 2030, and Henry Hub gas assumptions for 2022, compared to the prior year reflect expected near-term supply constraints. Brent oil assumptions post 2030 were revised downwards compared to the prior year, as bp expects an acceleration in the pace of transition to a low carbon economy. Aside from 2022, Henry Hub gas assumptions are unchanged from the prior year.

Given the significance of the price assumption revisions during 2021, alongside certain CGU specific new indicators, management tested most oil and gas CGUs for impairment and/or impairment reversal during the year. Management recorded $4.8 billion of pre-tax oil and gas CGU impairment reversals, in large part due to the oil and gas price upwards revisions detailed above, and $2.4 billion of pre-tax oil and gas CGU impairment charges. Further information has been provided in Note 1 on page 184 and Note 3 on page 198.

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 OP&O and G&LCE segments and are inherently uncertain. The estimation of future prices is subject to increased uncertainty given climate change, the global energy transition and COVID-19. There is a risk that management do not forecast reasonable 'best estimate' oil and gas price forecasts when assessing CGUs for impairment and/or reversal, leading to material misstatements. These price assumptions are highly judgmental and are pervasive inputs to bp's oil and gas CGU valuations, such that any misstatements would also aggregate. There is also a risk that management's oil and gas price related disclosures are not reasonable.

  The group's oil and gas price assumptions for value-in use impairment assessments are aligned with bp's investment appraisal assumptions, except that potential future emissions costs that could be borne by bp are included in investment appraisals as bp costs without assuming incremental revenue.

  As described in Note 1 on page 178, emissions costs forecasts interrelate with bp's oil and gas prices, because bp's price assumptions for value-in-use estimates represent 'net producer prices', i.e., net of any further emissions costs that may be enacted in the future. There is a risk management's judgement is not reasonable, that the potential impact of such further emissions costs being borne by producers including bp is not expected to have a material impact on the group's oil and gas CGU carrying values as costs would effectively be borne by oil and gas end users via overall higher commodity prices.

- **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 bp’s oil and gas CGU valuations, 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 and/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 OP&O and G&LCE segments.

We identified certain individual CGUs with a total carrying value of $33 billion which we determined would be most at risk of material impairment charges (and/or impairment reversals for CGUs with a combined $25 billion carrying value within this population) as a result of a plausible change in the oil and gas price assumptions. We identified that a subset of these CGUs were also individually materially sensitive to the discount rate assumption.

We also identified CGUs with a further $12 billion of combined carrying value which were less sensitive as they would be potentially at risk, in aggregate, to a material impairment by a plausible change in some or all of the key assumptions. No impairment reversals are available for these CGUs. Further information regarding these sensitivities is given in Note 1 on page 186.

Impairment and/or reversal assessments of upstream oil and gas PP&E assets remain a critical audit matter because recoverable values are reliant on forecasts that are inherently judgemental and complex for management to estimate, and the magnitude of the potential misstatement risk is material to the group.

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 and/or reversal 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 and the energy transition.
- The 2015 COP 21 Paris Agreement goals 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' was reaffirmed at COP 26 in Glasgow during November 2021. Nevertheless, we understand that certain stakeholders are focussed increasingly on the 'no greater than 1.5°C' ambition element of the Paris Agreement.
- We specifically analysed third party forecasts stated as being, or interpreted by us, as being consistent with scenarios achieving the Paris 'well below 2°C goal' and/or '1.5°C ambition' and considered whether they presented contradictory audit evidence.
- We challenged management’s judgement, described in Note 1 on page 179, that the potential impact of further emission costs being borne by producers including bp is not expected to have a material impact on the group’s oil and gas CGU carrying values. We inquired of certain third party forecasters included in our reasonable range and reviewed their forecast price reports, to understand whether their oil and gas prices are forecast on a ‘net producer prices’ basis, (i.e. net of potential future emissions costs that are assumed to be borne by oil and gas end users), consistent with the basis of bp’s value-in-use price assumptions.
- We assessed management’s disclosures in Notes 1 and 3, including the sensitivity of forecast revenue cash inflows to lower oil and gas prices and how climate change and the energy transition, potential future emissions costs and/or reduced demand scenarios may impact bp to a greater extent than currently anticipated in the group’s value-in-use estimates for oil and gas CGUs.

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 3 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 and assessed management’s CGU determinations, and considered whether there was any contradictory evidence present.

- We assessed whether bp's impairment methodology was acceptable under IFRS and tested the integrity and mechanical accuracy of certain impairment models.
- We challenged and assessed 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. We assessed whether management's forecasts are consistent overall with bp's strategy, including the group's expectation to reduce its hydrocarbon production (by around 40% by 2030 relative to 2019).
- 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. Decommissioning provisions – Notes 1 and 22

Critical Audit Matter Description

A decommissioning provision of $16.4 billion has been recognised in the financial statements at 31 December 2021. The estimation of decommissioning provisions is a highly judgemental area as it involves a number of key estimates related to the cost and timing of decommissioning, as well as inflation and discount rate. Given management expects hydrocarbon production to be around 40% lower by 2030 relative to 2019 as stated on page 17, consistency of that expectation with the timing of decommissioning expenditure and underlying cost assumptions is a key consideration. The estimated undiscounted cost of its obligations and the timing of future payment are set out in Note 1 on page 191.

Economic factors, future activities and the legislative environments that bp operates in are used to inform cost estimates, whereas the timing of decommissioning activities is dependent on cessation of production (CoP) dates, which are sensitive to changes in bp's price forecasts as price estimates determine economic cut off of oil and gas reserve estimates.

The inflation rate used in bp's decommissioning provision calculations has remained unchanged during 2021 at 1.5%. The impact of inflation on the forecast cost assumptions is an area of specific focus given the significant and sustained inflationary increases experienced globally since early 2021. In the second quarter of 2021 bp reduced its discount rate used for calculating its decommissioning provisions from 2.5% to 2.0% due to ongoing challenging macroeconomic conditions decreasing US treasury bond rates.

Additionally, bp is potentially exposed to decommissioning obligations that could revert back to bp in respect of historical divestments to third parties. Judgement is required to assess the potential risk of reversion and if applicable, the estimated exposure, for each historically divested asset. The risk of possible exposure was enhanced due to the impacts of the COVID-19 pandemic and climate change, which have heightened liquidity and financial resilience concerns for many industry participants. The risk has further increased following a US legal judgement in the year which required a specific provision and increased the likelihood of decommissioning liabilities reverting to former owners as part of a bankruptcy proceeding.

Provisions for decommissioning 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 curtail their operational lives. As disclosed in Note 1 on page 191 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. Management has conducted analysis which supports a conclusion 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.

We determined this to be a critical audit matter given the high degree of auditor judgment and the increased extent of effort by senior members of the engagement team.

How the Critical Audit Matter was addressed in the Audit

We obtained an understanding of the group's decommissioning estimate and provisioning process and evaluated the effectiveness of the relevant controls.

Cost and timing estimates

- We assessed the completeness and accuracy of the assets subject to decommissioning, including understanding the process to establish whether a legal or constructive obligation existed.
- We evaluated changes in key cost assumptions including rig rates, vessel rates, well plug and abandonment duration and non-productive time assumptions. We also assessed the reasonableness of key cost assumptions with reference to internal and appropriate third party data.
- We considered the expectation that demand for oil and gas products and related activities will decrease, primarily in response to climate change and energy transition effects pivoting future energy industry investment and development activity towards renewable sources. We challenged management's assessment of the impact this will have on the decommissioning provisions.
- We assessed changes in assumptions for the estimated date of decommissioning and evaluated whether CoP dates used for decommissioning estimation are aligned with CoP assumptions in other areas, including PP&E impairment testing and oil and gas reserve estimation.
- We assessed the accuracy of bp's additional disclosure of the estimated undiscounted cost of its obligations and the timing of future decommissioning payments.

Inflation and discount rates

- With the help of our valuation specialists, we evaluated the discount and inflation rate assumptions used, comparing them against latest external market data.
- We challenged how management has considered the current high level of inflation in setting 2021 decommissioning cost assumptions.
- We tested the decommissioning models, assessing the application of cost, timing, inflation and discount rate assumptions when calculating the final provisions.

Reversion risk

- We obtained an understanding of the group's decommissioning reversion risk assessment process, noting that the process was enhanced during 2021 in direct response to the increased potential default risk in respect of historical divestments to third parties.
- We tested management's key internal controls within this enhanced process, including those controls over the completeness and accuracy of the previously divested asset data.

- We challenged management's key judgements related to the decommissioning reversion risk and conclusions on whether any additional provision should be recognised or specific contingent liability disclosure made. We assessed the relevant internal and external evidence used in forming this judgement, including the financial health of the counterparty or counterparties in the ownership chain for the divested assets and the existence of any other pertinent factors which could indicate a higher probability of decommissioning obligations reverting to bp.

Potential decommissioning of refinery assets

- We challenged and evaluated 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 current intention to cease these activities. In making this evaluation, we considered internal and external demand forecasts and assessed external profitability benchmarking.
- We also met with refinery management to understand the potential alternative use cases under consideration for refineries in the future, which include options for the production of low carbon and sustainable fuels.

3. Accounting for complex transactions executed by the trading and shipping (T&S) function to deliver against the wider group strategy and valuation of commodity financial derivatives, where fraud risks may arise in revenue recognition (potentially impacting all financial statement accounts, in particular finance debt) - Notes 1, 19, 21, 28 and 29 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. Amongst other things, to achieve bp's 'net zero' ambition and to support the group strategy, T&S as a function is increasingly focused on executing long term renewable power offtake/supply contracts in existing and new markets whilst providing solutions to bp's customer through offering eco-friendly hydro-carbons. The nature of these transactions requires significant audit effort to be directed towards challenging management's adopted accounting treatment and/ or valuation estimates.

Throughout the year, we have kept our risk assessment updated by undertaking a review of portfolio composition. This process aided a deeper understanding of the impact of commodity price volatility, demand destruction resulting from the COVID-19 pandemic and the changing structure of the markets, including the impact of the transition to renewables across all regions where bp operates, allowing us to focus our audit effort to areas of highest risk.

Accounting for structured commodity transactions (SCTs):
T&S may also enter into a variety of transactions which we refer to as structured commodity transactions (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
- reference 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 a feature of these transactions is that they often include multiple elements that will have a material impact on the presentation and disclosure in the financial statements, including in particular the classification of liabilities as finance debt.

Valuation of commodity financial derivatives:
Commodity markets remained volatile during the year on the back of continuing demand uncertainty as a result of the pandemic and supply disruptions following geo-political tensions. In response to the volatility observed, we focused our audit efforts across valuation of all commodity derivatives and designed procedures to specifically test for management bias.

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.

As at 31 December 2021, the group's total financial assets and liabilities measured at fair value were $12.8 billion and $13.9 billion, of which level 3 derivative financial assets were $5.5 billion and level 3 derivative financial liabilities were $3.9 billion.

How the Critical Audit Matter was addressed in the Audit

Accounting for structured commodity transactions:
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 discussions with management and reading transaction documents and executed agreements.
- Performed a detailed accounting analysis for a sample of SCTs involving significant day one profits, offtake arrangements and/or significant contractual commitments. We confirmed that any day one profits were appropriately deferred.
- Selected a sample of existing working capital arrangements and financing structures to assess whether associated trading activity was in compliance with boundary conditions and whether the conclusions reached remained in compliance with relevant accounting standards.
- For SCTs which were identified during the prior years and that continue through 2021, we have refreshed our assessment in 2021 taking account of any amendments to the contracts. We assessed whether the conclusions reached previously remain appropriate and in accordance with relevant accounting standards.

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

Valuation of commodity financial derivatives:
In response to the increased volatility observed in the market and to test for management bias, we altered the extent and timing of our procedures by performing an independent valuation of a sample of distinct Level 2 derivatives at 30 June, 30 September and 31 December, and on a sample of

distinct Level 3 derivatives at 30 September and 31 December. In addition, we have focused our testing on price inputs where bp has substantial exposure to illiquid (Level 3) or long dated (Level 2) curves.

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 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
  - 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.

4. Impairment of E&A assets and refinery PP&E as a consequence, inter alia, of climate change and the energy transition – Notes 1, 3 and 14

Critical Audit Matter Description

Intangible Assets
The recoverability of certain of the group's $4.3 billion total exploration and appraisal (E&A) assets capitalised at 31 December 2021 are inherently judgemental and are potentially exposed to climate change and the global energy transition risk factors (see Note 14). This is because a greater number of E&A projects may not proceed as a consequence of lower forecast future oil and gas prices and bp's intention to reduce its hydrocarbon production. The determination of whether and when E&A costs should be written off, impaired, or retained on the balance sheet as E&A assets, remains complex, continues to require significant management judgement for certain E&A projects.

PP&E
The recoverability of certain of the group's $18.1 billion PP&E refining assets capitalised at 31 December 2021 are judgmental due to forecasting of cash flows and other key inputs of such assets which are impacted by the changes in supply and demand which arise as a consequence of climate change and the energy transition. Impairment tests were performed to assess the recoverability of each refinery's carrying values. As disclosed in Note 3 to the accounts on page 200, management has recorded impairment charges of $962 million in the C&P segment, which primarily related to their refining assets.

bp's intention to reduce its hydrocarbon production (by around 40% by 2030 relative to 2019) and the group's wider strategy includes potentially disposing of certain high emissions intensity upstream oil assets and others. As a consequence for certain assets judgement is required in the determination of the recoverable amount as to whether it should consider the estimated disposal proceeds from a third party as a key input. Management recorded $1.1 billion of pre-tax impairment charges in 2021 for such potential disposals as described in Note 3. There is an audit risk that management judgements taken to determine whether impairment charges are required based on bp's view of whether transactions are likely to proceed or not, and bp's strategic appetite regarding the value of disposal consideration that would be accepted, are not reasonable.

How the Critical Audit Matter Was Addressed in the Audit

We 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 recoverability of E&A assets capitalised at 31 December 2021 we:

- Obtained an understanding of the group's E&A write-off and impairment assessment processes and tested management's key internal controls, including the controls that assess climate change related risks.
- Challenged and evaluated 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 for 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 external press releases, meeting minutes, licence documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms.
- Assessed whether the progression of any projects that remain on the balance sheet would be inconsistent with elements of bp's strategy and in particular its net zero carbon commitments, bp's intention to reduce its hydrocarbon production (by around 40% by 2030 relative to 2019), and the group's 'no exploration in new countries' commitment.

In respect of the recoverability of PP&E refining assets capitalised at 31 December 2021 we:

- tested management's internal controls over the impairment evaluation
- assessed the valuation methodology, discount rate, including testing of source information and the mathematical accuracy of the calculation
- evaluated management's ability to forecast future cash flows and margins by comparing actual results to historical forecasts
- evaluated the cash flows and other key inputs of the impairment testing of PP&E refining assets by considering internal and external market studies of future supply and demand and conducting sensitivity analysis and
- assessed the integrity and mechanical accuracy of the impairment models and assessed the appropriateness of key assumptions and inputs.

We challenged management's analysis, that identified the specific assets that are likely to be disposed of by the group as part of its strategy. Where relevant, we challenged bp's asset impairment assessments based on their estimated disposal proceeds and whether transactions are judged likely to proceed or not. We obtained evidence of any negotiations with third parties; and carefully considered the group's strategic intent in this context.

/s/ Deloitte LLP

London
United Kingdom
18 March 2022

We have served as the company's auditor since 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 of 31 December 2021, based on the criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting relating to internal control over financial reporting (UK FRC Guidance). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of 31 December 2021, 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 2021, of the Company and our report dated 18 March 2022, expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company's change in accounting principle.

Basis for opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Definition and limitations of internal control over financial reporting

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

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

/s/ Deloitte LLP
London, United Kingdom
18 March 2022

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	**2021**	2020	2019
Sales and other operating revenues[a]	5	**157,739**	105,944	159,307
Earnings from joint ventures – after interest and tax	15	**543**	(302)	576
Earnings from associates – after interest and tax	16	**3,456**	(101)	2,681
Interest and other income	6	**581**	663	769
Gains on sale of businesses and fixed assets	3	**1,876**	2,874	193
Total revenues and other income		**164,195**	109,078	163,526
Purchases[a]	18	**92,923**	57,682	90,582
Production and manufacturing expenses		**25,843**	22,494	21,815
Production and similar taxes	4	**1,308**	695	1,547
Depreciation, depletion and amortization	4	**14,805**	14,889	17,780
Net impairment and losses on sale of businesses and fixed assets	3	**(1,121)**	14,381	8,075
Exploration expense	7	**424**	10,280	964
Distribution and administration expenses		**11,931**	10,397	11,057
Profit (loss) before interest and taxation		**18,082**	(21,740)	11,706
Finance costs	6	**2,857**	3,115	3,489
Net finance (income) expense relating to pensions and other post-retirement benefits	23	**(2)**	33	63
Profit (loss) before taxation		**15,227**	(24,888)	8,154
Taxation	8	**6,740**	(4,159)	3,964
Profit (loss) for the year		**8,487**	(20,729)	4,190
Attributable to				
bp shareholders		**7,565**	(20,305)	4,026
Non-controlling interests		**922**	(424)	164
		8,487	(20,729)	4,190
Earnings per share				
Profit (loss) for the year attributable to bp shareholders				
Per ordinary share (cents)				
Basic	10	**37.57**	(100.42)	19.84
Diluted	10	**37.33**	(100.42)	19.73
Per ADS (dollars)				
Basic	10	**2.25**	(6.03)	1.19
Diluted	10	**2.24**	(6.03)	1.18

[a] 2020 and 2019 numbers have been restated as a result of changes to the presentation of revenues and purchases relating to physically settled derivative contracts effective 1 January 2021. For more information see Note 1 Basis of preparation - *Voluntary change in accounting policy*.

Group statement of comprehensive income[a]

For the year ended 31 December				$ million
	Note	2021	2020	2019
Profit (loss) for the year		**8,487**	(20,729)	4,190
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**(921)**	(1,843)	1,538
Exchange (gains) losses on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**36**	(353)	880
Cash flow hedges marked to market	29	**(430)**	78	(100)
Cash flow hedges reclassified to the income statement	29	**255**	(37)	106
Costs of hedging marked to market	29	**(105)**	42	(4)
Costs of hedging reclassified to the income statement	29	**21**	22	57
Share of items relating to equity-accounted entities, net of tax	15, 16	**44**	312	82
Income tax relating to items that may be reclassified	8	**65**	66	(70)
		(1,035)	(1,713)	2,489
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	23	**4,416**	170	328
Cash flow hedges that will subsequently be transferred to the balance sheet	29	**1**	7	(3)
Income tax relating to items that will not be reclassified	8	**(1,317)**	(105)	(157)
		3,100	72	168
Other comprehensive income		**2,065**	(1,641)	2,657
Total comprehensive income		**10,552**	(22,370)	6,847
Attributable to				
bp shareholders		**9,654**	(21,983)	6,674
Non-controlling interests		**898**	(387)	173
		10,552	(22,370)	6,847

[a] See Note 31 for further information.

Group statement of changes in equity[a]

$ million

	Share capital and capital reserves	Treasury shares	Foreign currency translation reserve	Fair value reserves	Profit and loss account	bp shareholders' equity	Non-controlling interests Hybrid bonds	Non-controlling interests Other interest	Total equity
At 1 January 2021	**46,701**	**(13,224)**	**(8,719)**	**(808)**	**47,300**	**71,250**	**12,076**	**2,242**	**85,568**
Profit for the year	**—**	**—**	**—**	**—**	**7,565**	**7,565**	**507**	**415**	**8,487**
Other comprehensive income	**—**	**—**	**(846)**	**(209)**	**3,144**	**2,089**	**—**	**(24)**	**2,065**
Total comprehensive income	**—**	**—**	**(846)**	**(209)**	**10,709**	**9,654**	**507**	**391**	**10,552**
Dividends[b]	**—**	**—**	**—**	**—**	**(4,316)**	**(4,316)**	**—**	**(311)**	**(4,627)**
Cash flow hedges transferred to the balance sheet, net of tax	**—**	**—**	**—**	**(10)**	**—**	**(10)**	**—**	**—**	**(10)**
Repurchase of ordinary share capital[c]	**—**	**—**	**—**	**—**	**(3,151)**	**(3,151)**	**—**	**—**	**(3,151)**
Share-based payments, net of tax	**170**	**600**	**—**	**—**	**(138)**	**632**	**—**	**—**	**632**
Share of equity-accounted entities' changes in equity, net of tax	**—**	**—**	**—**	**—**	**556**	**556**	**—**	**—**	**556**
Issue of perpetual hybrid bonds[a]	**—**	**—**	**—**	**—**	**(26)**	**(26)**	**950**	**—**	**924**
Payments on perpetual hybrid bonds	**—**	**—**	**(7)**	**—**	**—**	**(7)**	**(492)**	**—**	**(499)**
Tax on issue of perpetual hybrid bonds	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Transactions involving non-controlling interests, net of tax	**—**	**—**	**—**	**—**	**881**	**881**	**—**	**(387)**	**494**
At 31 December 2021	**46,871**	**(12,624)**	**(9,572)**	**(1,027)**	**51,815**	**75,463**	**13,041**	**1,935**	**90,439**
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

[a] See Note 31 for further information.
[b] See Note 9 for further information.
[c] See Note 30 for further information.

Group balance sheet

At 31 December			$ million
	Note	**2021**	2020
Non-current assets			
Property, plant and equipment	11	**112,902**	114,836
Goodwill	13	**12,373**	12,480
Intangible assets	14	**6,451**	6,093
Investments in joint ventures	15	**9,982**	8,362
Investments in associates	16	**21,001**	18,975
Other investments	17	**2,544**	2,746
Fixed assets		**165,253**	163,492
Loans		**922**	840
Trade and other receivables	19	**2,693**	4,351
Derivative financial instruments	29	**7,006**	9,755
Prepayments		**479**	533
Deferred tax assets	8	**6,410**	7,744
Defined benefit pension plan surpluses	23	**11,919**	7,957
		194,682	194,672
Current assets			
Loans		**355**	458
Inventories	18	**23,711**	16,873
Trade and other receivables	19	**27,139**	17,948
Derivative financial instruments	29	**5,744**	2,992
Prepayments		**2,486**	1,269
Current tax receivable		**542**	672
Other investments	17	**280**	333
Cash and cash equivalents	24	**30,681**	31,111
		90,938	71,656
Assets classified as held for sale	2	**1,652**	1,326
		92,590	72,982
Total assets		**287,272**	267,654
Current liabilities			
Trade and other payables	21	**52,611**	36,014
Derivative financial instruments	29	**7,565**	2,998
Accruals		**5,638**	4,650
Lease liabilities	27	**1,747**	1,933
Finance debt	25	**5,557**	9,359
Current tax payable		**1,554**	1,038
Provisions	22	**5,256**	3,761
		79,928	59,753
Liabilities directly associated with assets classified as held for sale	2	**359**	46
		80,287	59,799
Non-current liabilities			
Other payables	21	**10,567**	12,112
Derivative financial instruments	29	**6,356**	5,404
Accruals		**968**	852
Lease liabilities	27	**6,864**	7,329
Finance debt	25	**55,619**	63,305
Deferred tax liabilities	8	**8,780**	6,831
Provisions	22	**19,572**	17,200
Defined benefit pension plan and other post-retirement benefit plan deficits	23	**7,820**	9,254
		116,546	122,287
Total liabilities		**196,833**	182,086
Net assets		**90,439**	85,568
Equity			
bp shareholders' equity	31	**75,463**	71,250
Non-controlling interests	31	**14,976**	14,318
Total equity	31	**90,439**	85,568

Helge Lund Chair
Bernard Looney Chief executive officer
18 March 2022

Group cash flow statement

For the year ended 31 December				$ million
	Note	2021	2020	2019
Operating activities				
Profit (loss) before taxation		**15,227**	(24,888)	8,154
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	7	**167**	9,920	631
Depreciation, depletion and amortization	4	**14,805**	14,889	17,780
Impairment and (gain) loss on sale of businesses and fixed assets	3	**(2,997)**	11,507	7,882
Earnings from joint ventures and associates		**(3,999)**	403	(3,257)
Dividends received from joint ventures and associates		**1,842**	1,442	1,962
Interest receivable		**(235)**	(258)	(441)
Interest received		**320**	74	416
Finance costs	6	**2,857**	3,115	3,489
Interest paid		**(2,474)**	(2,728)	(2,870)
Net finance expense relating to pensions and other post-retirement benefits	23	**(2)**	33	63
Share-based payments		**627**	723	730
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	23	**(655)**	(282)	(238)
Net charge for provisions, less payments		**2,934**	735	(176)
(Increase) decrease in inventories		**(7,458)**	3,963	(3,406)
(Increase) decrease in other current and non-current assets		**(13,263)**	4,230	(2,335)
Increase (decrease) in other current and non-current liabilities		**20,095**	(8,278)	2,823
Income taxes paid		**(4,179)**	(2,438)	(5,437)
Net cash provided by operating activities		**23,612**	12,162	25,770
Investing activities				
Expenditure on property, plant and equipment, intangible and other assets		**(10,887)**	(12,306)	(15,418)
Acquisitions, net of cash acquired		**(186)**	(44)	(3,562)
Investment in joint ventures		**(1,440)**	(567)	(137)
Investment in associates		**(335)**	(1,138)	(304)
Total cash capital expenditure		**(12,848)**	(14,055)	(19,421)
Proceeds from disposals of fixed assets	3	**1,145**	491	500
Proceeds from disposals of businesses, net of cash disposed	3	**5,812**	4,989	1,701
Proceeds from loan repayments		**197**	717	246
Net cash used in investing activities		**(5,694)**	(7,858)	(16,974)
Financing activities				
Repurchase of shares		**(3,151)**	(776)	(1,511)
Lease liability payments		**(2,082)**	(2,442)	(2,372)
Proceeds from long-term financing		**6,987**	14,736	8,597
Repayments of long-term financing		**(16,804)**	(12,179)	(7,118)
Net increase (decrease) in short-term debt		**1,077**	(1,234)	180
Issue of perpetual hybrid bonds		**924**	11,861	—
Payments relating to perpetual hybrid bonds		**(538)**	(89)	—
Payments relating to transactions involving non-controlling interests (other)		**(560)**	(8)	—
Receipts relating to transactions involving non-controlling interests (other)		**683**	665	566
Dividends paid				
bp shareholders	9	**(4,304)**	(6,340)	(6,946)
Non-controlling interests		**(311)**	(238)	(213)
Net cash provided by (used in) financing activities		**(18,079)**	3,956	(8,817)
Currency translation differences relating to cash and cash equivalents		**(269)**	379	25
Increase (decrease) in cash and cash equivalents		**(430)**	8,639	4
Cash and cash equivalents at beginning of year		**31,111**	22,472	22,468
Cash and cash equivalents at end of year		**30,681**	31,111	22,472

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 2021 were approved and signed by the chief executive officer and chairman on 18 March 2022 having been duly authorized to do so by the board of directors. BP p.l.c. is a public limited company incorporated and domiciled in England and Wales. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), IFRS as adopted 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. As a result of the UK's withdrawal from the EU, with effect from 1 January 2021, the consolidated financial statements are also prepared in accordance with IFRS as adopted by the UK. IFRS as adopted by the UK does not differ from IFRS as adopted by the EU. IFRS as adopted by the UK and EU differs in certain respects from IFRS as issued by the IASB. The differences have no impact on the group's consolidated financial statements for the years presented. The UK's withdrawal from the EU has not had 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 2021. 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 investments in Rosneft and Aker BP; 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. The group's assumptions for investment appraisal (see page 32) form part of an investment decision-making framework for currently unsanctioned future capital expenditure on property, plant and equipment, and intangibles including exploration and appraisal assets, that is designed to support the effective and resilient implementation of bp's strategy. The price assumptions used for investment appraisal include oil and gas price assumptions, which are producer prices and are therefore net of any future carbon prices that the purchaser may be required to pay, and an assumption of a single carbon emissions cost imposed on the producer in respect of operational greenhouse gas (GHG) emissions (carbon dioxide and methane) in order to incentivize engineering solutions to mitigate GHG emissions on projects. The group's oil, gas and carbon price assumptions for value-in-use impairment testing are aligned with those investment appraisal assumptions, except for, 2022 oil and gas prices which reflect near-term market conditions, and the assumptions for future carbon emissions costs described below.

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 price assumptions for value-in-use impairment testing was revised during 2021. The assumption up to 2030 was increased to reflect near-term supply constraints whereas the long-term assumption was decreased as bp's management expects an acceleration of the pace of transition to a lower carbon economy. Henry Hub gas price assumptions remain unchanged from 2020 except that the assumption for 2022 has been increased to reflect short-term market conditions. The revised assumptions sit within the range of external scenarios considered by management and are in line with a range of transition paths consistent with the temperature goal of the Paris climate change agreement, 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.

As noted above, the group's investment appraisal process includes a single carbon emissions price assumption for the investment economics which is applied to bp's anticipated share of bp's forecast of the investments assets' scope 1 and 2 GHG emissions where they exceed defined thresholds, and is assumed to be payable by bp as the producer or as a non-operator. However, for value-in-use impairment testing on bp's existing cash generating units (CGUs), consistent with all other relevant cash flows estimated, bp is required to reflect management's best estimate of any expected applicable carbon emission costs payable by bp, including where bp in not the operator, in the future for each jurisdiction in which the group has interests. This requires management's best estimate of how future changes to relevant carbon emission cost policies and/or legislation are likely to affect the future cash flows of the group's applicable CGUs, whether currently enacted or not. Future potential carbon pricing and/or costs of carbon emissions allowances are included in the value-in-use calculations to the extent management has sufficient information to make such an estimate. Currently this results in limited application of carbon price assumptions in value-in-use impairment tests given that carbon pricing legislation in most jurisdictions where the group has interests is not in place and there is not sufficient information available as to the relevant policy makers' future intentions regarding carbon pricing to support an estimate.

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

However, as bp's forecast future prices are producer prices, the group considers it reasonable to assume that if, in addition to the costs already in place, further scope 1 and 2 emission costs were partially to be borne directly by oil and gas producers including bp in future and the prevalence of such costs were to become widespread, the gross oil and gas prices realised by producers would be correspondingly higher over the long term, resulting in no expected overall materially negative impacts on the group's net cash flows. 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 and carbon costs.

Production assumptions within upstream property, plant and equipment, and goodwill value-in-use impairment tests reflect management's current best estimate of future production of the existing upstream portfolio. The group's sees the expected reduction in upstream hydrocarbon production by around 40% by 2030 from its 2019 baseline (see page 17) being achieved through future active management and high-grading of the portfolio. Changes in upstream production since 2019 will be included in the best estimate however as the specific future changes to the portfolio are not yet known, the current best estimate does not include the full extent of the expected upstream production reduction. See significant judgements and estimates: recoverability of asset carrying values and Note 13 for sensitivity analyses in relation to reasonably possible changes in production for upstream oil and gas properties and goodwill respectively.

Impairment reversals were recognized on certain upstream oil and gas properties partly as a result of the higher near-term assumptions. See Note 3 for further information.

For the customers & products segment, 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.

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. A significant proportion of exploration and appraisal intangible assets were written off in 2020 as a result of lower price assumptions and work to develop bp's new strategy. The recoverability of the remaining intangibles was considered during 2021 and no significant write-offs were identified. These assets will continue to be assessed as the energy transition progresses. See significant judgement: exploration and appraisal intangible assets and Note 7 for further information.

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 strategy, oil and natural gas production will remain an important part of bp's business activities over that period. Similarly, for refineries, demand for refined products is expected to remain sufficient to support the remaining useful life of existing assets. 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 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 existing upstream oil and gas properties are expected to start decommissioning within the next two decades. The group's expectation to reduce its upstream hydrocarbon production by around 40% by 2030 from its 2019 baseline (see page 17) is expected to be achieved through future active management and high-grading of the portfolio. Any resulting increases or decreases to the weighted average timing of decommissioning will be driven by the profile of assets held in the revised portfolio. Currently, the expected timing of decommissioning expenditures for the upstream oil and gas assets in the group's portfolio has not materially been brought forward. Management does not expect any reasonable change in the expected timing of decommissioning 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 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 28 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 nominal discount rate applied to provisions was reduced during the year to reflect the enduring reduction in US Treasury yields. The principal impact of this rate reduction was a $1.3 billion increase in the decommissioning provision with a corresponding increase in the carrying amount of property, plant and equipment of $1.0 billion. Impairment discount rates and country risk premiums were unchanged due to COVID-19 from those reported in 2020. See significant judgements and estimates: recoverability of asset carrying values and provisions for further information.

Pensions and other post-retirement benefits
The volatility in the financial markets during 2021 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 23 for further information.

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

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 and no significant impact was determined relative to the total expected credit loss allowances recognized as at 31 December 2021. Management does not consider the calculation of expected credit loss allowances to be a significant accounting estimate. See Note 20 and 28 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 8 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 securities issued by subsidiaries and for which the group has the unconditional right to avoid transferring cash or another financial asset to the holders. Profit or loss attributable to bp shareholders is adjusted to reflect the coupon/interest related to these hybrid securities 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 oil production & operations and gas & low carbon energy segments, 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 judgements: investments in Rosneft and Aker BP

Judgement is required in assessing the level of control or influence over another entity in which the group holds an interest. For bp, the judgements that the group had significant influence over Rosneft Oil Company (Rosneft), a Russian oil and gas company, and expects to continue to have significant influence over Aker BP, a Norwegian oil and gas company, following completion of Aker BP's proposed acquisition of Lundin Energy, are significant.

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. 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.

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

Rosneft

At 31 December 2021, bp owned 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 2021, Rosneftegaz held 40.4% (2020 40.4%) of the voting shares of Rosneft. 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, was approved as a member of the Rosneft board in 2013. He was also chairman of the Rosneft board's Strategic and Sustainable Development Committee during 2021. bp also held the voting rights at general meetings of shareholders conferred by its 19.75% stake in Rosneft. bp's economic interest in Rosneft at 31 December 2021 was 22.03% (2020 22.03%), which was higher than bp's ownership stake due to transactions by Rosneft in its own shares in previous years. bp's management considers, therefore, that the group has significant influence over Rosneft, as defined by IFRS, as at 31 December 2021. As a consequence of this judgement, bp used the equity method of accounting for its investment and bp's share of Rosneft's oil and natural gas reserves was included in the group's estimated net proved reserves of equity-accounted entities.

On 27 February 2022, bp announced it will exit its shareholding in Rosneft. bp's two nominated directors to the Rosneft board stepped down from that date and submitted letters of resignation. As a result, bp's management considers that the group no longer has significant influence over Rosneft, as defined by IFRS, from that date. Following the loss of significant influence, bp's equity accounting of its investment ceased from that date and the investment will be accounted for as an investment in an equity instrument measured at fair value, as described under 'Financial assets' below, instead. No share of Rosneft's oil and natural gas reserves will be reported going forward. See Note 37 Events after the reporting period for further information.

Aker BP

bp owned 27.85% of the voting shares of Aker BP at 31 December 2021 and significant influence was presumed. On completion of Aker BP's acquisition of Lundin Energy, which remains subject to shareholder and regulatory approval, bp expects its interest to be diluted to 15.9% of the voting shares of Aker BP as a result of new Aker BP shares being issued as partial consideration to Lundin Energy shareholders.

bp's group chief financial officer, Murray Auchincloss, has been a member of the Aker BP board since 2017. bp's other nominated director, Kate Thomson has been a member of the Aker BP board since formation of that company in 2016. She is also a member of the Aker BP board's Audit and Risk Committee. These memberships are not expected to change following the transaction. bp also holds the voting rights at general meetings of shareholders conferred by its stake in Aker BP. bp's management considers, therefore, that the group will retain significant influence, as defined by IFRS, over Aker BP following the acquisition of Lundin Energy.

As a consequence of this judgement, bp has classified $0.6 billion as an asset held for sale, reflecting the highly probable deemed disposal of a part of bp's equity accounted interest as a result of the transaction. If significant influence was not present following completion, the carrying amount of bp's entire interest in Aker BP would be classified as an asset held for sale.

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 chief executive officer, 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 4. bp changed its segmental reporting from 1 January 2021, see 'change in segmentation' 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, and equity accounting of associates and joint ventures is ceased 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 and appraisal expenditure

Oil and natural gas exploration and appraisal 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

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.

The carrying amount of capitalized costs are included in Note 7.

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.

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.

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 11 and Note 4 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 254, which is unaudited. Details on bp’s proved reserves and production compliance and governance processes are provided on page 348. The 2021 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 254.

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 on initial recognition are as follows:

Land improvements	15 to 25 years
Buildings	20 to 50 years
Refineries	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 to the extent that they are not already 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.

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, carbon pricing (where applicable), 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 13 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 11, Note 13 and Note 14.

The estimates for assumptions made in impairment tests in 2021 relating to discount rates and oil and gas properties are discussed below. Changes in the economic environment including as a result of the energy transition 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.

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

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 a post-tax discount rate.

The discount rates applied in impairment tests are reassessed each year and, in 2021, the post-tax discount rate was 6% (2020 6%) other than for low carbon energy assets where the risk profile of expected cash flows supported a lower rate of 4%. 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 (2020 1% to 3%). 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% (2020 7% to 15%) depending on the risk premium and applicable tax rate in the geographic location of the CGU.

Oil and natural gas properties

For oil and natural gas properties in the oil production & operations and gas & low carbon energy segments, expected future cash flows are estimated using management's best estimate of future oil and natural gas prices, and production and reserves and certain resources volumes. Forecast cash flows include the impact of all approved emission reduction projects. 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 2021, the group identified oil and gas properties in these segments with carrying amounts totalling $26,341 million (2020 $45,027 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. bp's carbon emissions cost assumptions and their interrelationship with oil and gas prices are described in 'Judgements and estimates made in assessing the impact of climate change and the transition to a lower carbon economy' on page 178. The investment appraisal price assumptions are recommended by the senior vice president economic & energy insights after considering a range of external price sets, and supply and demand profiles associated with 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 scenarios considered include those where those goals are met as well as those where they are not met.

During the year, bp's price assumptions applied in value-in-use impairment testing for Brent oil up to 2030 were increased to reflect near-term supply constraints. bp's management also expects an acceleration of the pace of transition to a lower carbon economy. As such, the long-term Brent oil assumptions were decreased during the year, reaching $55 per barrel by 2040 and $45 per barrel by 2050 (in 2020 real terms). The price assumptions applied in value-in-use impairment testing for Henry Hub gas were unchanged to those used in 2020 except that the assumption for 2022 was increased to reflect short term market conditions. These price assumptions are derived from the central case investment appraisal assumptions, adjusted where applicable to reflect short-term market conditions (see page 32). A summary of the group's revised price assumptions for Brent oil and Henry Hub gas, applied in 2021 and 2020, in real 2020 terms, is provided below. The assumptions represent management's best estimate of future prices at the balance sheet date, which sit within the range of external scenarios considered as appropriate for the purpose. They are considered by bp to be in line with a range of transition paths consistent with the temperature goal of the Paris climate change agreement, 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. However, they do not correspond to any specific Paris-consistent scenario. An inflation rate of 2% (2020 2%) is applied to determine the price assumptions in nominal terms.

2021 price assumptions	**2022**	**2025**	**2030**	**2040**	**2050**
Brent oil ($/bbl)	70	60	60	55	45
Henry Hub gas ($/mmBtu)	4.00	3.00	3.00	3.00	2.75

2020 price assumptions	**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

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.

The oil market continued its rebalancing process in 2021. Brent oil prices averaged $71/bbl in 2021. That is 70% higher than in 2020 and the second highest since 2015. Oil demand rebounded on the back of the economic recovery, supported by the increasing COVID-19 vaccination roll-out and gradual lifting of restrictions. On the supply side, continued active supply management by OPEC+ countries also helped accelerate the rebalancing process. bp's long-term assumption for oil prices is lower than the 2021 price average, based on the judgement that, in the long term, oil demand is likely to fall so that the price levels needed to encourage sufficient investment to meet declining global oil demand is also lower.

US gas prices almost doubled in 2021 to $3.9/mmbtu from $2.0/mmbtu in 2020. The higher prices reflect a tighter demand/supply balance for 2021 when compared to 2020. Early in the year, colder weather increased demand and decreased supply resulting in a large draw on storage and therefore the need to replenish it over the summer. Strong global GDP recovery also saw a recovery in LNG exports from the US relative to the shut-ins in 2020. Further, higher coal prices also supported gas prices through competition in the power sector. The level of US gas prices in 2021 is above bp's long term price assumption based on the judgement of the price level required to incentivize new 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

Management considers discount rates, oil and natural gas prices and production to be the key sources of estimation uncertainty in determining the recoverable amount of upstream oil and gas assets. The sensitivity analyses below, in addition to covering the key sources of estimation uncertainty, also indicate how the energy transition, potential future carbon emissions costs for operational GHG emissions and/or reduced demand for oil and gas may further impact forecast revenue cash inflows to a greater extent than currently anticipated in the group's value-in-use estimates for oil and gas CGUs, if carbon emissions costs were to be implemented as a deduction against revenue cash flows. The analyses therefore represent a net revenue sensitivity.

A change in net revenue from upstream oil and gas properties can arise either due to changes in oil and natural gas prices, carbon emissions costs/ carbon prices, changes in oil and natural gas production, or a combination of these.

Management tested the impact of a change in net revenue cash flows in value-in-use impairment testing up to a combined effect on net revenue of 20% in all future years.

Net revenue reductions of this magnitude in isolation could indicatively lead to a reduction in the carrying amount of bp's currently held upstream oil and gas properties in the range of $16-17 billion, which is approximately 14-15% of the net book value of property, plant and equipment as at 31 December 2021. If this net revenue reduction was solely due to reductions in oil prices in isolation, it reflects an indicative decrease in the carrying amount of using price assumptions for Brent oil broadly in the middle of the range of prices associated with a pre-publication version (see page 64) of the World Business Council for Sustainable Development (WBCSD) 'family' of scenarios considered to be consistent with limiting global average temperature to 1.5°C above pre-industrial levels.

Net revenue increases of this magnitude in isolation could indicatively lead to an increase in the carrying amount of bp's currently held upstream oil and gas properties in the range of $3-4 billion, which is approximately 3-4% of the net book value of property, plant and equipment as at 31 December 2021. This potential increase in the carrying amount would arise due to reversals of previously recognized impairments and represents approximately half of the total impairment reversal capacity available at 31 December 2021. If this net revenue increase was solely due to increases in oil prices in isolation, it reflects an indicative increase in the carrying amount of using price assumptions for Brent oil broadly at the top end of the range of prices associated with a pre-publication version of the WBCSD 'family' of scenarios considered to be consistent with limiting global average temperature to 1.5°C above pre-industrial levels.

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 analyses also assume the impact of increases in carbon price on operational GHG emissions are fully absorbed as a decrease in net revenue (and vice versa) rather than reflecting how carbon prices or other carbon emissions costs may ultimately be incorporated by the market. The above sensitivity analyses therefore do not reflect a linear relationship between net revenue and value that can be extrapolated. The interdependency of these inputs and 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. This level of change reflects past experience of a reasonable change in rate that could arise within the next financial year. If the discount rate was one percentage point higher across all tests performed, the net impairment reversal recognized in 2021 would have been approximately $1.3 billion lower. If the discount rate was one percentage point lower, the net impairment reversal recognized would have been approximately $0.6 billion higher.

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 $12.4 billion on its balance sheet (2020 $12.5 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. Of this, $7.6 billion relates to goodwill in the oil production & operations and gas & low carbon energy segments, for which oil and gas price and production assumptions are key sources of estimation uncertainty. Sensitivities and additional information relating to impairment testing of goodwill in these segments are provided in Note 13.

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

Inventories

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

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

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

Leases

Agreements that convey the right to control the use of an identified asset for a period of time in exchange for consideration are accounted for as leases. The right to control is conveyed if bp has both the right to obtain substantially all of the economic benefits from, and the right to direct the use of, the identified asset throughout the period of use. An asset is identified if it is explicitly or implicitly specified by the agreement and any substitution rights held by the lessor over the asset are not considered substantive.

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

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

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

Financial assets measured at fair value through other comprehensive income

Financial assets are classified as measured at fair value through other comprehensive income when they are held in a business model the objective of which is both to collect contractual cash flows and sell the financial assets, and the contractual cash flows represent solely payments of principal and interest.

Financial assets measured at fair value through profit or loss

Financial assets are classified as measured at fair value through profit or loss when the asset does not meet the criteria to be measured at amortized cost or fair value through other comprehensive income. Such assets are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are included in this category.

Investments in equity instruments

Investments in equity instruments are subsequently measured at fair value through profit or loss unless an election is made on an instrument-by-instrument basis to recognize 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 assess 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 28 - Liquidity risk for further information.

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

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.

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 or when accounting under the equity method is discontinued. 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 29.

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 2.0% (2020 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, if material, 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 utilization 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 shipping & 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, primarily in the comparative period, 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 $0.5 billion of decommissioning provisions should be recognized as at 31 December 2021 (2020 no significant provisions) for assets previously 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 (see Note 32 for further information).

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. Portfolio strength and flexibility are such that the point of cessation of manufacturing at the group's operating refineries cannot yet be reliably determined for the purposes of determining 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 2021 was 2.0% (2020 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 17 years (2020 18 years) and 6 years (2020 6 years) respectively. Costs at future prices are determined by applying an inflation rate of 1.5% (2020 1.5%) to decommissioning costs and 2% (2020 2%) for all other provisions. A lower rate is typically applied to decommissioning as certain costs are expected to remain fixed at current or past prices.

The estimated phasing of undiscounted cash flows in real terms for upstream decommissioning is approximately $5.3 billion (2020 $3.9 billion) within the next 10 years, $6.9 billion (2020 $7.7 billion) in 10 to 20 years and the remainder of approximately $6.0 billion (2020 $6.0 billion) after 20 years. The timing and amount of decommissioning cash flows are inherently uncertain and therefore the phasing is management's current best estimate but may not be what will ultimately occur.

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 increase in the nominal discount rate applied could decrease the group's provision balances by approximately $1.4 billion (2020 $1.2 billion). The pre-tax impact on the group income statement would be a credit of approximately $0.4 billion (2020 $0.3 billion). This level of change reflects past experience of a reasonable change in rate that could arise within the next financial year.

The discounting impact on the group's decommissioning provisions for oil and gas properties in the oil productions & operations and gas & low carbon energy segments of a two-year change in the timing of expected future decommissioning expenditures is approximately $0.2 billion (2020 $0.3 billion). 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, then these decommissioning provisions would increase by approximately $1.6 billion (2020 $1.4 billion) and a pre-tax charge of approximately $0.4 billion (2020 $0.5 billion) would be recognized.

As described in Note 32, 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.

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 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 23.

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, at the time of the transaction, affects neither accounting profit nor taxable profit or loss and, at the time of the transaction, does not give rise to equal taxable and deductible temporary differences.
- 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, at the time of the transaction, affects neither accounting profit nor taxable profit or loss and, at the time of the transaction, does not give rise to equal taxable and deductive temporary differences.

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

In respect of deductible temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

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

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

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

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

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

In addition, the group has carry-forward tax losses and tax credits in certain taxing jurisdictions that are available to offset against future taxable profit. However, deferred tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused tax losses or tax credits can be utilized. Management judgement is exercised in assessing whether this is the case and estimates are required to be made of the amount of future taxable profits that will be available. 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 8 and Note 32.

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 2021 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.

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

Sales and purchase of commodities accounted for under IFRS 15 are presented on a gross basis in Revenue from contracts with customers and Purchases respectively. Physically settled derivatives which represent trading or optimization activities are presented net alongside financially settled derivative contracts in Other operating revenues within Sales and other operating income. Certain physically settled sale and purchase derivative contracts which are not part of trading and optimization activities are presented gross within Other operating revenues and Purchases respectively. Changes in the fair value of derivative assets and liabilities prior to physical delivery are also classified as other operating revenues.

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 II' – Amendments to IFRS 9 'Financial instruments', IFRS 16 'Leases' and other IFRSs with effect from 1 January 2021. 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 II'

The replacement of key interest rate benchmarks such as the London Inter-bank Offered Rate (LIBOR) with alternative benchmarks in the US, UK, EU and other territories occurred at the end of 2021 for most benchmarks, with remaining USD LIBOR tenors expected to cease in 2023. bp is primarily exposed to 3 month USD LIBOR that will be available until June 2023.

Amendments to IFRS 9, IFRS 16 and other IFRSs were issued by the IASB in August 2020 to provide practical expedients and reliefs when changes are made to contractual cash flows or hedging relationships because of the transition from Inter-bank Offered Rates to alternative risk-free rates. bp adopted these amendments from 1 January 2021 and they were applied prospectively from that date. See Note 28 for further information.

bp has an internal working group on interest rate benchmark reform to monitor market developments and manage the transition to alternative benchmark rates. The impacts on contracts and arrangements that are linked to interest rate benchmarks, for example, borrowings, leases and derivative contracts, have been assessed and transition plans have either been executed or are being developed. bp is also participating on external committees and task forces dedicated to interest rate benchmark reform.

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.

Other changes to significant accounting policies

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, from that date, by the chief operating decision maker, who for bp is the chief executive officer. From the first quarter of 2021, the group's reportable segments 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 marketing and trading activities and the group's solar, wind and hydrogen businesses. 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 customer-focused businesses, spanning convenience and mobility, which includes retail and fuels next-gen offers such as electrification, as well as aviation, midstream and Castrol lubricants. It also includes our oil products businesses, refining & trading. The petrochemicals business is also 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 was unchanged and continues to include equity-accounted earnings from the group's investment in Rosneft. The group will cease to report Rosneft as a separate segment in the group's financial reporting for 2022. See Note 37 Events after the reporting period.

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

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 4 for further information.

Comparative information for 2019 and 2020 has been restated in Notes 3, 4 and 13 to reflect the changes in reportable segments. References to segments have also changed in Notes 2, 7, 15 and 27.

Voluntary change in accounting policy - Net presentation of revenues and purchases relating to physically settled derivative contracts from 1 January 2021

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 previously presented revenues and purchases for such contracts on a gross basis in the 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 organizational changes to implement the strategy from 1 January 2021, resulted 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, from that date. Physically settled derivative contracts were previously presented on a gross basis and included in other operating revenues and purchases; however, under the new accounting policy, such contracts will be presented on a net basis within other operating revenues to the extent that they relate to trading or optimization activities.

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 optimization, 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 is more closely aligned with how management monitors and manages performance of such contracts. Comparative information for sales and other operating revenues and purchases for 2019 and 2020 has been restated as shown in the table below. There is no impact on comparative information for profit before income tax or earnings per share.

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

$ million	2020	2020 Restated	Impact of net presentation	2019	2019 Restated	Impact of net presentation
Segment revenues (Note 4)						
gas & low carbon energy	18,467	16,275	(2,192)	28,102	27,045	(1,057)
oil production & operations	17,234	17,234	—	28,702	28,702	—
customers & products	162,974	90,744	(72,230)	250,897	132,864	(118,033)
other businesses & corporate	1,666	1,666	—	1,418	1,418	—
	200,341	125,919	(74,422)	309,119	190,029	(119,090)
Less: sales and other revenues between segments						
gas & low carbon energy	2,708	2,708	—	3,097	3,097	—
oil production & operations	15,879	15,879	—	25,870	25,870	—
customers & products	158	158	—	973	973	—
other businesses & corporate	1,230	1,230	—	782	782	—
	19,975	19,975	—	30,722	30,722	—
External sales and other operating revenues						
gas & low carbon energy	15,759	13,567	(2,192)	25,005	23,948	(1,057)
oil production & operations	1,355	1,355	—	2,832	2,832	—
customers & products	162,816	90,586	(72,230)	249,924	131,891	(118,033)
other businesses & corporate	436	436	—	636	636	—
Total sales and other operating revenues	**180,366**	**105,944**	**(74,422)**	**278,397**	**159,307**	**(119,090)**
Sales and other operating revenues (Note 5)						
Sales and other operating revenues include the following in relation to revenues from contracts with customers:						
Crude oil	5,048	5,048	—	9,141	9,141	—
Oil products	63,564	63,564	—	102,408	102,408	—
Natural gas, LNG and NGLs	12,726	10,762	(1,964)	18,909	15,156	(3,753)
Non-oil products and other revenues from contracts with customers	9,840	9,779	(61)	12,169	10,838	(1,331)
Revenues from contracts with customers	**91,178**	**89,153**	**(2,025)**	**142,627**	**137,543**	**(5,084)**
Other operating revenues	89,188	16,791	(72,397)	135,770	21,764	(114,006)
Total sales and other operating revenues	**180,366**	**105,944**	**(74,422)**	**278,397**	**159,307**	**(119,090)**
Purchases	**132,104**	**57,682**	**(74,422)**	**209,672**	**90,582**	**(119,090)**

2. Non-current assets held for sale

The carrying amount of assets classified as held for sale at 31 December 2021 is $1,652 million (2020 $1,326 million), with associated liabilities of $359 million (2020 $46 million).

oil productions & operations

As announced in August 2021, bp and PetroChina have agreed to establish Basra Energy Company, an incorporated joint venture, intended to own and manage the companies' interests in the Rumaila field in Iraq. Subject to regulatory and other approvals, the transaction is expected to complete during the first half of 2022. Assets of $1,009 million and associated liabilities of $333 million have been classified as held for sale in the group balance sheet at 31 December 2021.

On 21 December 2021, Aker BP, an associate of bp, announced the proposed acquisition of Lundin Energy for consideration in cash and new Aker BP shares. Subject to regulatory and other approvals, the transaction is expected to complete mid-year 2022. bp currently holds a 27.9% interest in Aker BP. Following the transaction this is expected to become a 15.9% interest in the combined company. $595 million of bp's investment in AkerBP has therefore been classified as held for sale in the group's balance sheet.

No transactions have been classified as held for sale during 2021 which were completed by 31 December 2021.

gas & low carbon energy

The assets held for sale balance at 31 December 2020 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 agreed to sell this interest to PTT Exploration and Production Public Company Limited of Thailand. The sale was approved by Royal Decree on 28 March 2021 and $2.4 billion was received in March 2021.

The total assets and liabilities held for sale at 31 December 2021 and 2020, which are all in gas & low carbon energy and oil productions & operations, are set out in the table below.

		$ million
	2021	2020
Property, plant and equipment	**35**	1,099
Goodwill	**137**	199
Investments in associates	**632**	—
Inventories	**152**	—
Trade and other receivables	**696**	28
Assets classified as held for sale	**1,652**	1,326
Trade and other payables	**(238)**	(36)
Lease liabilities	**(74)**	—
Provisions	**(47)**	(10)
Liabilities directly associated with assets classified as held for sale	**(359)**	(46)

3. Disposals and impairment

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

			$ million
	2021	2020	2019
Gains on sale of businesses and fixed assets			
gas & low carbon energy	**1,034**	—	—
oil production & operations	**869**	360	143
customers & products	**(52)**	2,320	50
other businesses & corporate	**25**	194	—
	1,876	2,874	193

			$ million
	2021	2020	2019
Losses on sale of businesses and fixed assets, and closures			
gas & low carbon energy	**1**	9	884
oil production & operations	**86**	375	409
customers & products	**142**	296	57
other businesses & corporate	**1**	1	9
	230	681	1,359
Impairment losses			
gas & low carbon energy	**834**	6,214	387
oil production & operations	**1,617**	6,723	6,365
customers & products	**962**	840	65
other businesses & corporate	**63**	12	30
	3,476	13,789	6,847
Impairment reversals			
gas & low carbon energy	**(2,338)**	(3)	—
oil production & operations	**(2,479)**	(86)	(131)
customers & products	**(7)**	—	—
other businesses & corporate	**(3)**	—	—
	(4,827)	(89)	(131)
Impairment and losses on sale of businesses and fixed assets, and closures	**(1,121)**	14,381	8,075

Disposals

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

			$ million
	2021	2020	2019
Proceeds from disposals of fixed assets	**1,145**	491	500
Proceeds from disposals of businesses, net of cash disposed	**5,812**	4,989	1,701
	6,957	5,480	2,201
By business			
gas & low carbon energy	**2,425**	38	565
oil production & operations	**3,022**	1,157	1,472
customers & products	**1,050**	3,959	152
other businesses & corporate	**460**	326	12
	6,957	5,480	2,201

Information for 2019 and 2020 has been restated to reflect the changes in reportable segments. For more information see Note 1 Significant accounting policies, judgements, estimates and assumptions - Change in segmentation.

Proceeds from disposals of business in 2021 includes $2,364 million in respect of the disposal of a 20% participating interest in Block 61 in Oman and a further $2,177 million and $872 million in respect of the Alaska and Petrochemicals disposals which concluded in 2020. At 31 December 2021, deferred consideration relating to disposals amounted to $205 million receivable within one year (2020 $1,291 million and 2019 $159 million) and $823 million receivable after one year (2020 $2,402 million and 2019 $125 million). The deferred consideration principally relates to the disposals of our Alaskan business in 2020. In addition, contingent consideration receivable relating to disposals amounted to $1,917 million at 31 December 2021 (2020 $1,999 million and 2019 $598 million). The contingent consideration at 31 December 2021 relates to the prior period disposals of our Alaskan business and certain assets in the North Sea. These amounts of contingent consideration are reported within Other investments on the group balance sheet - see Note 17 for further information.

During the year, the group disposed of a $1,675 million loan note related to the Alaska divestment. As a result of potential partial recourse from the counterparty, the group continues to recognize an asset of $547 million and an associated liability of $598 million, both of which will reduce over time.

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

gas & low carbon energy

In 2021 gains on disposal of businesses and fixed assets were principally related to a $1,031 million gain on disposal of a 20% participating interest in Block 61 in Oman.

3. Disposals and impairment – continued

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.

oil production & operations

In 2021 gains principally resulted from adjustments to disposals in prior periods. Gains include $171 million from the disposal of a 2.1% interest in Aker BP in the North Sea, $100 million from the disposal of certain exploration assets in Brazil, and $502 million fair value movements in relation to deferred and contingent consideration in relation to prior disposals in Alaska and the North Sea.

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.

customers & products

In 2020, gains principally resulted from the $2.3 billion gain recognized on the disposal of our Petrochemicals business which completed in December 2020. The gain was adjusted in 2021 as a result of post settlement adjustments. 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.

Summarized financial information relating to the sale of businesses is shown in the table below.

The principal transaction categorized as a business disposal in 2021 was the sale of a 20% participating interest from bp’s 60% participating interest in Block 61 in Oman. See Note 2 for further information.

The principal transactions categorized as a business disposal in 2020 were the sales of our Petrochemical and Alaskan businesses.

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.

			$ million
	2021	2020	2019
Non-current assets	**1,620**	9,092	1,653
Current assets	**69**	1,539	507
Non-current liabilities	**(287)**	(1,639)	(257)
Current liabilities	**(3)**	(782)	(108)
Total carrying amount of net assets disposed	**1,399**	8,210	1,795
Recycling of foreign exchange on disposal	**35**	(328)	880
Costs on disposal	**(5)**	13	190
	1,429	7,895	2,865
Gains (losses) on sale of businesses	**1,632**	2,570	(1,190)
Total consideration	**3,061**	10,465	1,675
Non-cash consideration	**(108)**	(219)	(938)
Consideration received (receivable)[a]	**2,859**	(5,257)	964
Proceeds from the sale of businesses, net of cash disposed[b]	**5,812**	4,989	1,701

[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 $2 million (2020 $101 million and 2019 $30 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 11, and Note 14 for further information on impairments by asset category.

gas & low carbon energy

The 2021 impairment loss of $834 million primarily relates to losses incurred in respect of development assets in the Tortue CGU in Mauritania & Senegal ($819 million) and principally arose as a result of increased forecast future expenditure. The 2021 impairment reversal of $2,338 million primarily relates to reversals in respect of producing assets in the KGD6 CGU in India ($1,229 million) and the Trinidad CGU ($600 million) and principally arose as a result of changes to the group's oil and gas price assumptions and re-assessment of reserves.The recoverable amount of these CGUs on which significant impairment charges or reversals were recognized, based on their value in use, is $7,365 million. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2021 in total, based on their value in use, is $17,330 million.

The 2020 impairment loss of $6,214 million primarily relates to losses incurred in respect of producing and development assets in Trinidad ($2,416 million), Mauritania and Senegal ($1,909 million) and India ($1,313 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 was $13,563 million.

The 2019 impairment losses of $387 million related to a number of different assets, with the most significant charges arising in Egypt and Trinidad.

oil production & operations

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

3. Disposals and impairment – continued

The 2021 impairment loss of $1,617 million principally relates to anticipated portfolio changes ($1,109 million). The 2021 impairment reversals of $2,479 million principally arose as a result of changes to the group’s oil and gas price assumptions and re-assessment of reserves. They include amounts in BPX Energy ($1,356 million) and the North Sea ($950 million). The principal CGU on which a significant impairment reversal was recognized was $982 million for Hawkville in BPX Energy. The recoverable amount of these CGUs on which significant impairment charges or reversals were recognized, based on their value in use, is $6,760 million. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2021, based on their value in use, is $16,586 million.

The 2020 impairment loss of $6,723 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), 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 2019 impairment losses of $6,365 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.

customers & products

2021 impairment losses of $962 million principally relates to anticipated portfolio changes in the products business ($595 million).

Impairment losses totalling $840 million and $65 million were recognized in 2020 and 2019 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.

Other businesses and corporate

Impairment losses totalling $63 million, $12 million, and $30 million were recognized in 2021, 2020 and 2019 respectively.

4. Segmental analysis

During the first quarter of 2021, the group's reportable segments were changed consistent with a change in the way that resources are allocated and performance is assessed from that date, by the chief operating decision maker, who for bp is the chief executive officer. From the first quarter of 2021, the group's reportable segments 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 marketing and trading activities and the group's solar, wind and hydrogen businesses. 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 customer-focused businesses, spanning convenience and mobility, which includes fuels retail and next-gen offers such as electrification, as well as aviation, midstream, and Castrol lubricants. It also includes our oil products businesses, refining & trading. The petrochemicals business is 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.

The Rosneft segment was unchanged and continues to include equity-accounted earnings from the group's investment in Rosneft. The group will cease to report Rosneft as a separate segment in the group's financial reporting for 2022. See Note 37 Events after the reporting period.

Other businesses and corporate comprises the group’s shipping and treasury functions, and corporate activities worldwide.

2020 and 2019 have been restated in Notes 4 and 13 to reflect the changes in reportable segments. References to segments have also changed in Notes 2, 7, 15 and 27.

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 customers & products.

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

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

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

4. Segmental analysis – continued

							$ million
							2021
By business	gas & low carbon energy	oil production & operations	customers & products	Rosneft	other businesses & corporate	Consolidation adjustment and eliminations	Total group
Segment revenues							
Sales and other operating revenues	30,840	24,519	130,095	—	1,724	(29,439)	157,739
Less: sales and other operating revenues between segments	(4,563)	(22,408)	(1,226)	—	(1,242)	29,439	—
Third party sales and other operating revenues	26,277	2,111	128,869	—	482	—	157,739
Earnings from joint ventures and associates – after interest and tax	426	576	385	2,694	(82)	—	3,999
Segment results							
Replacement cost profit (loss) before interest and taxation	2,133	10,501	2,208	2,429	(2,777)	(67)	14,427
Inventory holding gains (losses)[a]	33	8	3,355	259	—	—	3,655
Profit (loss) before interest and taxation	2,166	10,509	5,563	2,688	(2,777)	(67)	18,082
Finance costs							(2,857)
Net finance expense relating to pensions and other post-retirement benefits							2
Profit before taxation							15,227
Other income statement items							
Depreciation, depletion and amortization							
US	80	3,174	1,349	—	94	—	4,697
Non-US	4,384	3,354	1,651	—	719	—	10,108
Charges for provisions, net of write-back of unused provisions, including change in discount rate	173	7	3,063	—	477	—	3,720
Segment assets							
Investments in joint ventures and associates	5,224	8,044	3,291	14,354	70	—	30,983
Additions to non-current assets[b]	4,963	6,090	3,940	—	1,007	—	16,000

[a] See explanation of inventory holding gains and losses on page 200.

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

4. Segmental analysis – continued

By business	gas & low carbon energy	oil production & operations	customers & products	Rosneft	other businesses & corporate	Consolidation adjustment and eliminations	Total group
							$ million
							2020
Segment revenues							
Sales and other operating revenues	16,275	17,234	90,744	—	1,666	(19,975)	105,944
Less: sales and other operating revenues between segments	(2,708)	(15,879)	(158)	—	(1,230)	19,975	—
Third party sales and other operating revenues	13,567	1,355	90,586	—	436	—	105,944
Earnings from joint ventures and associates – after interest and tax	(45)	(327)	214	(229)	(16)	—	(403)
Segment results							
Replacement cost profit (loss) before interest and taxation	(7,068)	(14,583)	3,418	(149)	(579)	89	(18,872)
Inventory holding gains (losses)[a]	19	(2)	(2,796)	(89)	—	—	(2,868)
Profit (loss) before interest and taxation	(7,049)	(14,585)	622	(238)	(579)	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	96	3,700	1,359	—	39	—	5,194
Non-US	3,361	4,087	1,631	—	616	—	9,695
Charges for provisions, net of write-back of unused provisions, including change in discount rate	(2)	58	1,903	—	543	—	2,502
Segment assets							
Investments in joint ventures and associates	3,663	8,154	3,671	11,808	41	—	27,337
Additions to non-current assets[b]	3,507	5,321	5,359	—	570	—	14,757

[a] See explanation of inventory holding gains and losses on page 200.

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

4. Segmental analysis – continued

By business	gas & low carbon energy	oil production & operations	customers & products	Rosneft	other businesses & corporate	Consolidation adjustment and eliminations	Total group
							$ million
							2019
Segment revenues							
Sales and other operating revenues	27,045	28,702	132,864	—	1,418	(30,722)	159,307
Less: sales and other operating revenues between segments	(3,097)	(25,870)	(973)	—	(782)	30,722	—
Third party sales and other operating revenues	23,948	2,832	131,891	—	636	—	159,307
Earnings from joint ventures and associates – after interest and tax	81	518	374	2,295	(11)	—	3,257
Segment results							
Replacement cost profit (loss) before interest and taxation	2,945	1,049	6,502	2,316	(1,848)	75	11,039
Inventory holding gains (losses)[a]	(6)	(2)	685	(10)	—	—	667
Profit (loss) before interest and taxation	2,939	1,047	7,187	2,306	(1,848)	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	79	4,614	1,335	—	34	—	6,062
Non-US	5,067	4,552	1,586	—	513	—	11,718
Charges for provisions, net of write-back of unused provisions, including change in	(9)	127	507	—	560	—	1,185
Segment assets							
Investments in joint ventures and associates	4,695	9,038	3,609	12,927	56	—	30,325
Additions to non-current assets[b]	7,609	9,705	4,011	—	1,288	—	22,613

[a] See explanation of inventory holding gains and losses on page 200.
[b] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

By geographical area	US	Non-US	Total
			$ million
			2021
Revenues			
Third party sales and other operating revenues[a]	**53,748**	**103,991**	**157,739**
Other income statement items			
Production and similar taxes	**108**	**1,200**	**1,308**
Non-current assets			
Non-current assets[b c]	**54,395**	**108,793**	**163,188**

[a] Non-US region includes UK $11,248 million
[b] Non-US region includes UK $19,530 million
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

By geographical area	US	Non-US	Total
			$ million
			2020
Revenues			
Third party sales and other operating revenues[a]	27,413	78,531	105,944
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 $13,836 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.

4. Segmental analysis – continued

By geographical area	US	Non-US	$ million 2019 Total
Revenues			
Third party sales and other operating revenues[a]	47,951	111,356	159,307
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 $17,169 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. Sales and other operating revenues

	2021	2020	$ million 2019
Crude oil	**5,483**	5,048	9,141
Oil products	**101,418**	63,564	102,408
Natural gas, LNG and NGLs	**24,378**	10,762	15,156
Non-oil products and other revenues from contracts with customers	**6,082**	9,779	10,838
Revenue from contracts with customers	**137,361**	89,153	137,543
Other operating revenues[a]	**20,378**	16,791	21,764
Total sales and other operating revenues	**157,739**	105,944	159,307

[a] Principally relates to commodity derivative transactions.

2020 and 2019 amounts have been restated as a result of changes to the presentation of revenues and purchases relating to physically settled derivative contracts effective 1 January 2021. See Note 1 - Voluntary change in accounting policy - Net presentation of revenues and purchases relating to physically settled derivative contracts.

An analysis of third-party sales and other operating revenues by segment and region is provided in Note 4.

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

6. Income statement analysis

	2021	2020	$ million 2019
Interest and other income			
Interest income from			
Financial assets measured at amortized cost	**221**	215	371
Financial assets measured at fair value through profit or loss	**5**	25	49
Other income	**355**	423	349
	581	663	769
Currency exchange losses charged to the income statement[a]	**345**	38	37
Expenditure on research and development	**266**	332	364
Costs relating to the Gulf of Mexico oil spill (pre-interest and tax)[b]	**70**	255	319
Finance costs			
Interest expense on lease liabilities	**288**	337	379
Interest expense on other liabilities measured at amortized cost[c]	**1,820**	2,166	2,410
Capitalized at 2.63% (2020 2.75% and 2019 3.50%)[d]	**(287)**	(345)	(374)
Losses arising on finance debt risk management activities[e]	**145**	—	—
Unwinding of discount on provisions	**391**	437	505
Unwinding of discount on other payables measured at amortized cost	**500**	520	569
	2,857	3,115	3,489

[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] 2021 includes a loss of $195 million (2020 loss of $158 million) associated with the buyback of finance debt.
[d] Tax relief on capitalized interest is approximately $66 million (2020 $83 million and 2019 $51 million).
[e] From 2021 temporary valuation differences associated with the group's interest rate and foreign currency exchange risk management of finance debt are being presented within finance costs. Previously these were presented within production and manufacturing expenses. Relevant amounts in the comparative periods were not reclassified as the amounts were not material.

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

The following financial information represents the amounts included within the group totals relating to activity associated with the exploration for and evaluation of oil and natural gas resources. All such activity is recorded within the gas & low carbon energy and oil production & operations segments.

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

			$ million
	2021	2020	2019
Exploration and evaluation costs			
Exploration expenditure written off[a]	**167**	9,920	631
Other exploration costs	**257**	360	333
Exploration expense for the year	**424**	10,280	964
Impairment losses	**1**	156	2
Intangible assets – exploration and appraisal expenditure[b c]	**4,289**	4,113	14,091
Liabilities	**98**	71	73
Net assets	**4,191**	4,042	14,018
Cash used in operating activities	**257**	360	333
Cash used in investing activities	**260**	674	1,215

[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.

[b] 2019 includes approximately $2,500 million relating to Canadian oil sands.

[c] Amount capitalized at 31 December 2021 and 31 December 2020 relates to assets in various regions. The largest of these is approximately $700 million capitalized in the Middle East region (2020 approximately $700 million capitalized in the Middle East Region).

8. Taxation

Tax on profit

			$ million
	2021	2020	2019
Current tax			
Charge for the year	**4,808**	2,095	5,316
Adjustment in respect of prior years	**138**	50	(68)
	4,946	2,145	5,248
Deferred tax			
Origination and reversal of temporary differences in the current year	**3,366**	(7,826)	(1,190)
Adjustment in respect of prior years[a]	**(1,572)**	1,522	(94)
	1,794	(6,304)	(1,284)
Tax charge (credit) on profit or loss	**6,740**	(4,159)	3,964

[a] The adjustments in respect of prior years reflect the reassessment of the deferred tax balances for prior periods in light of changes in facts and circumstances during the year; 2021 and 2020 include the impact of the reassessment of deferred tax asset recognition in light of revisions to price assumptions.

In 2021, the total tax charge recognized within other comprehensive income was $1,252 million (2020 $39 million charge and 2019 $227 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 31 for further information.

8. Taxation – continued

The total tax charge recognized directly in equity was $170 million (2020 $154 million charge and 2019 $37 million charge). 2021 mainly relates to transactions involving non-controlling interests and 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.

			$ million
	2021	2020	2019
Profit (loss) before taxation	**15,227**	(24,888)	8,154
Tax charge (credit) on profit or loss	**6,740**	(4,159)	3,964
Effective tax rate	**44%**	17%	49%

			%
Tax rate computed at the weighted average statutory rate[a]	**54**	31	52
Increase (decrease) resulting from			
Tax reported in equity-accounted entities[b c]	**(3)**	—	(4)
Adjustments in respect of prior years	**(9)**	(6)	(2)
Deferred tax not recognized	**8**	(3)	(2)
Tax incentives for investment	**(1)**	1	(3)
Disposal impacts[d]	**(4)**	—	1
Items not deductible for tax purposes	**1**	(3)	4
Other[c]	**(2)**	(3)	3
Effective tax rate	**44**	17	49

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

[b] Includes withholding tax in respect of distributions from equity-accounted entities.

[c] A minor amendment has been made to 2019 to align with current period presentation. The impact in 2020 is not material.

[d] 2021 primarily relates to the divestment of a 20% stake in Oman Block 61.

Deferred tax

		$ million
Analysis of movements during the year in the net deferred tax (asset) liability	**2021**	2020
At 1 January	**(913)**	5,190
Exchange adjustments	**9**	55
Charge (credit) for the year in the income statement	**1,794**	(6,304)
Charge for the year in other comprehensive income	**1,302**	48
Charge for the year in equity	**170**	154
Acquisitions and disposals	**8**	(56)
At 31 December	**2,370**	(913)

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

					$ million
		Income statement			Balance sheet
	2021	2020	2019	**2021**	2020
Deferred tax liability					
Depreciation	**899**	(7,295)	(1,436)	**16,276**	15,361
Pension plan surpluses	**105**	69	(31)	**3,898**	2,691
Derivative financial instruments	**(33)**	33	29	**24**	63
Other taxable temporary differences[a]	**180**	(32)	159	**1,782**	1,562
	1,151	(7,225)	(1,279)	**21,980**	19,677
Deferred tax asset					
Depreciation	**(846)**	(849)	—	**(1,678)**	(849)
Lease liabilities	**(43)**	286	264	**(1,128)**	(1,122)
Pension plan and other post-retirement benefit plan deficits	**119**	2	62	**(1,221)**	(1,548)
Decommissioning, environmental and other provisions	**(744)**	438	(472)	**(7,891)**	(7,155)
Derivative financial instruments	**(9)**	—	63	**(75)**	(25)
Tax credits	**1,282**	310	(336)	**(2,359)**	(3,652)
Loss carry forward	**1,064**	543	12	**(4,202)**	(5,319)
Other deductible temporary differences	**(180)**	191	402	**(1,056)**	(920)
	643	921	(5)	**(19,610)**	(20,590)
Net deferred tax charge (credit) and net deferred tax (asset) liability[b]	**1,794**	(6,304)	(1,284)	**2,370**	(913)
Of which – deferred tax liabilities				**8,780**	6,831
– deferred tax assets				**6,410**	7,744

[a] This category includes deferred tax in respect of temporary differences on unremitted earnings of equity-accounted entities.

[b] Included within the net deferred tax (asset) liability is a deferred tax asset balance of $3,959 million (2020 $5,471 million) related to the Gulf of Mexico oil spill.

8. Taxation – continued

Of the $6,410 million of deferred tax assets recognized on the group balance sheet at 31 December 2021 (2020 $7,744 million), $6,342 million (2020 $7,659 million) relates to entities that have suffered a loss in either the current or preceding period. This amount is supported by forecasts consistent with bp's future oil and gas price assumptions that indicate sufficient future taxable profits will be available to utilize such assets within any applicable expiry period. For 2021, this mainly includes $2,224 million in the US, $892 million in the UK, $762 million in India and $541 million in Angola (2020 mainly included $3,906 million in the US, $707 million in India, $637 million in Australia and $588 million in Trinidad & Tobago).

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	**2021**	2020
Unused US state tax losses[a]	**2.5**	2.4
Unused tax losses – other jurisdictions[b]	**6.0**	6.0
Unused tax credits	**28.2**	26.9
of which – arising in the UK[c]	**24.6**	23.0
– arising in the US[d]	**3.6**	3.9
Deductible temporary differences[e]	**49.0**	46.1
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	**0.7**	0.8

[a] For 2021 these losses expire in the period 2022-2041 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 2021 the US unused tax credits expire in the period 2022-2031.
[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	**2021**	2020	2019
Current tax benefit relating to the utilization of previously unrecognized deferred tax assets	**331**	46	272
Deferred tax benefit arising from the reversal of a previous write-down of deferred tax assets	**773**	11	96
Deferred tax benefit relating to the recognition of previously unrecognized deferred tax assets	**820**	—	364
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	**29**	1,622	73

9. Dividends

The quarterly dividend which is expected to be paid on 25 March 2022 in respect of the fourth quarter 2021 is 5.46 cents per ordinary share ($0.3276 per American Depositary Share (ADS)). The corresponding amount in sterling was announced on 15 March 2022.

	Pence per share			Cents per share			$ million		
	2021	2020	2019	**2021**	2020	2019	**2021**	2020	2019
Dividends announced and paid in cash									
Preference shares							**2**	1	1
Ordinary shares									
March	**3.7684**	8.1558	7.7382	**5.25**	10.50	10.25	**1,063**	2,102	1,435
June	**3.7118**	8.3421	8.0655	**5.25**	10.50	10.25	**1,062**	2,119	1,779
September	**3.9529**	4.0433	8.3475	**5.46**	5.25	10.25	**1,100**	1,059	1,656
December	**4.1045**	3.9169	7.8250	**5.46**	5.25	10.25	**1,077**	1,059	2,075
	15.5376	24.4581	31.9762	**21.42**	31.50	41.00	**4,304**	6,340	6,946
Dividend announced, paid in March 2022				**5.46**			**1,065**		

The amount of unclaimed dividends recognized as a liability in other payables at 31 December 2021 is $62 million (2020 $50 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 2021 dividend expected to be paid on 25 March 2022.

	2021	2020	2019
Number of shares issued (thousand)	**–**	—	208,927
Value of shares issued ($ million)	**–**	—	1,387

The financial statements for the year ended 31 December 2021 do not reflect the dividend announced on 8 February 2022 and which is expected to be paid in March 2022; this will be treated as an appropriation of profit in the year ending 31 December 2022.

10. Earnings per share

Per ordinary share	2021	2020	Cents per share 2019
Basic earnings per share	**37.57**	(100.42)	19.84
Diluted earnings per share	**37.33**	(100.42)	19.73

Per American Depositary Share (ADS)[a]	2021	2020	Dollars per share 2019
Basic earnings per share	**2.25**	(6.03)	1.19
Diluted earnings per share	**2.24**	(6.03)	1.18

[a] One ADS is equivalent to six ordinary shares.

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.

	2021	2020	$ million 2019
Profit attributable to bp shareholders	**7,565**	(20,305)	4,026
Less: dividend requirements on preference shares	**2**	1	1
Profit for the year attributable to bp ordinary shareholders	**7,563**	(20,306)	4,025

	2021	2020	Shares thousand 2019
Basic weighted average number of ordinary shares	**20,128,862**	20,221,514	20,284,859
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**131,526**	—	114,811
Weighted average number of ordinary shares outstanding used to calculate diluted earnings per share	**20,260,388**	20,221,514	20,399,670

	2021	2020	Shares thousand 2019
Basic weighted average number of ordinary shares – ADS equivalent	**3,354,810**	3,370,252	3,380,809
Potential dilutive effect of ordinary shares (ADS equivalent) issuable under employee share-based payment plans	**21,921**	—	19,136
Weighted average number of ordinary shares (ADS equivalent) outstanding used to calculate diluted earnings per share	**3,376,731**	3,370,252	3,399,945

The number of ordinary shares outstanding at 31 December 2021, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 19,642,221,041. Between 31 December 2021 and 1 March 2022, the latest practicable date before the completion of these financial statements, there was a net decrease of 217,722,532 of ordinary shares primarily as a result of share buy backs.

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 116-141.

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	2021		2020	
	Number of options[a b] thousand	**Weighted average exercise price $**	Number of options[a b] thousand	Weighted average exercise price $
Outstanding	**590,961**	**4.26**	28,171	3.79
Exercisable	**1,080**	**4.73**	1,874	5.02
Dilutive effect	**3,588**	**n/a**	2,497	n/a

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

[b] At 31 December 2021 the quoted market price of one bp ordinary share was £3.31 (2020 £2.55).

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.

10. Earnings per share – continued

Share plans	2021	2020
	Number of shares[a]	Number of shares[a]
Vesting	thousand	thousand
Within one year	92,210	87,517
1 to 2 years	149,077	85,720
2 to 3 years	179,449	147,097
3 to 4 years	109,265	749
Over 4 years	928	349
	530,929	321,432
Dilutive effect	152,899	104,068

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

There has been a net decrease of 15,265,059 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2021 and 1 March 2022.

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

$ million

	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
Cost - owned PP&E								
At 1 January 2021	**3,872**	**1,210**	**214,323**	**42,914**	**2,418**	**3,049**	**10,276**	**278,062**
Exchange adjustments	**(205)**	**(19)**	**—**	**(736)**	**(31)**	**(16)**	**(627)**	**(1,634)**
Additions	**68**	**59**	**7,931**	**2,187**	**171**	**40**	**762**	**11,218**
Acquisitions	**—**	**—**	**—**	**1**	**—**	**—**	**—**	**1**
Transfers from intangible assets	**—**	**—**	**38**	**—**	**—**	**—**	**—**	**38**
Reclassified as assets held for sale	**—**	**—**	**(7,399)**	**—**	**—**	**—**	**—**	**(7,399)**
Deletions and disposals	**(22)**	**(5)**	**(6,859)**	**(329)**	**(327)**	**(40)**	**(170)**	**(7,752)**
At 31 December 2021	**3,713**	**1,245**	**208,034**	**44,037**	**2,231**	**3,033**	**10,241**	**272,534**
Depreciation - owned PP&E								
At 1 January 2021	**692**	**631**	**140,551**	**20,031**	**1,845**	**2,381**	**5,786**	**171,917**
Exchange adjustments	**(29)**	**(10)**	**—**	**(370)**	**(21)**	**(12)**	**(373)**	**(815)**
Charge for the year	**48**	**36**	**10,193**	**1,502**	**158**	**71**	**523**	**12,531**
Impairment losses	**4**	**—**	**2,340**	**937**	**—**	**12**	**4**	**3,297**
Impairment reversals	**—**	**(3)**	**(4,794)**	**—**	**—**	**(30)**	**—**	**(4,827)**
Reclassified as assets held for sale	**—**	**—**	**(7,399)**	**—**	**—**	**—**	**—**	**(7,399)**
Deletions and disposals	**(9)**	**—**	**(6,341)**	**(259)**	**(190)**	**(34)**	**(157)**	**(6,990)**
At 31 December 2021	**706**	**654**	**134,550**	**21,841**	**1,792**	**2,388**	**5,783**	**167,714**
Owned PP&E - net book amount at 31 December 2021	**3,007**	**591**	**73,484**	**22,196**	**439**	**645**	**4,458**	**104,820**
Right-of-use assets - net book amount at 31 December 2021[b]	**—**	**1,331**	**32**	**617**	**15**	**2,513**	**3,574**	**8,082**
Total PP&E - net book amount at 31 December 2021	**3,007**	**1,922**	**73,516**	**22,813**	**454**	**3,158**	**8,032**	**112,902**
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 and disposals	(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 and disposals	(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
Assets under construction included above								
At 31 December 2021								**19,704**
At 31 December 2020								17,259
Depreciation charge for the year on right-of-use assets								
2021		**209**	**27**	**279**	**10**	**844**	**613**	**1,982**
2020		192	43	637	10	829	579	2,290

[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] $203 million (2020 $284 million) of drilling rig right-of-use assets and $2,230 million (2020 $2,521 million) of shipping vessel right-of-use assets are included in Plant, machinery and equipment and Transportation respectively.

12. 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 2021 amounted to $8,208 million (2020 $8,009 million, 2019 $11,382 million). bp has contracted capital commitments amounting to $1,075 million (2020 $1,087 million, 2019 $77 million) in relation to joint ventures and $126 million (2020 $183 million, 2019 $787 million) in relation to associates. bp's share of contracted capital commitments of joint ventures amounted to $1,383 million (2020 $900 million, 2019 $1,024 million).

13. Goodwill and impairment review of goodwill

		$ million
	2021	2020
Cost		
At 1 January	**13,093**	12,865
Exchange adjustments	**(91)**	184
Acquisitions and other additions[a]	**139**	632
Reclassified as assets held for sale	**(137)**	(199)
Deletions and disposals	**(13)**	(389)
At 31 December	**12,991**	13,093
Impairment losses		
At 1 January	**613**	997
Exchange adjustments	**(1)**	1
Impairment losses for the year	**7**	1
Deletions and disposals	**(1)**	(386)
At 31 December	**618**	613
Net book amount at 31 December	**12,373**	12,480
Net book amount at 1 January	**12,480**	11,868

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

Impairment review of goodwill

		$ million
Goodwill at 31 December	**2021**	2020
gas & low carbon energy	**2,147**	2,152
oil production & operations	**5,464**	5,613
customers & products	**4,697**	4,660
other businesses & corporate	**65**	55
	12,373	12,480

Information for 2019 and 2020 has been restated to reflect the changes in reportable segments. For more information see Note 1 Significant accounting policies, judgements, estimates and assumptions - *Change in segmentation.*

Goodwill acquired through business combinations has been allocated to groups of cash-generating units (CGUs) that are expected to benefit from the synergies of the acquisition. For oil production & operations goodwill is allocated to CGUs in aggregate at the segment level, for gas & low carbon energy goodwill is allocated to the hydrocarbon CGUs within the segment. For customers and products, goodwill has been allocated to Castrol, 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.

gas & low carbon energy and oil production & operations

As a result of the change in bp's reporting segments on 1 January 2021, a review of the level at which goodwill is allocated and monitored for impairment testing purposes was required. Oil and gas properties CGUs were allocated to the new segments based on whether they predominantly produce oil or gas. No individual CGUs were split between the new segments and the existing CGUs remained unchanged. Legacy upstream goodwill was allocated to the two groups of CGUs allocated to the new segments based on the relative aggregate recoverable value of each group. An impairment test was performed on the goodwill balances allocated to the oil production & operations and the gas & low carbon energy segments at 1 January 2021 after the change in segments; no impairment of either goodwill balance was identified as a result thereof.

		$ million		$ million
	gas & low carbon energy		**oil production & operations**	
	2021	2020	**2021**	2020
Goodwill	**2,147**	2,152	**5,464**	5,613
Excess of recoverable amount over carrying amount	**3,991**	3,991	**32,438**	27,758

The table above shows the carrying amount of goodwill for the segments 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. For oil production & operations the increase in headroom relates to movements due to the passage of time.

No impairment of the goodwill balances in either gas & low carbon energy or oil production & operations was recognized during 2021 (2020 $nil million).

13. Goodwill and impairment review of goodwill – continued

The value in use for relevant CGUs in both gas & low carbon energy and oil production & operations is based on the cash flows expected to be generated by the projected production profiles up to the expected dates of cessation of production of each field, based on appropriately risked estimates of reserves and resources. Midstream and supply and trading activities and equity-accounted entities are generally not included in the impairment reviews of goodwill, as they do not represent part of the grouping of CGUs to which the goodwill balances relate and which are used to monitor the goodwill balances for internal management purposes. Where such activities form part of wider CGUs to which goodwill relates 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 in both gas & low carbon energy and oil & production operations. 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 field has specific reservoir characteristics and economic circumstances, the cash flows of each field are 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 plans. 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 average production for the purposes of goodwill impairment testing in the gas & low carbon energy segment over the next 15 years is 261 mmboe per year (2020 275 mmboe per year) and in the oil production and operations segment is 604 mmboe per year (2020 602 mmboe per year). Production assumptions used for the goodwill impairment tests in both gas & low carbon energy and oil production & operations reflect management's best estimate of future production of the existing portfolio at the time of the calculation. The group's expectation to reduce upstream hydrocarbon production by around 40% by 2030 from its 2019 baseline is expected to be achieved through future active management and high-grading of the portfolio. Changes in upstream production since 2019 will be included in the best estimates however as the specific future changes to the portfolio are not yet known, these best estimates do not include the full extent of the expected upstream production reductions.

The weighted average pre-tax discount rate used in the review for both segments is 11% (2020 11% for both segments).

The most recent reviews for impairment for the oil production & operations and gas & low carbon energy segments were carried out in the fourth quarter. As permitted by IAS 36, the detailed calculations for recoverable amounts performed in 2020 were used as a basis for the 2021 impairment tests. The recoverable amounts, key assumptions and sensitivity calculations for 2021 are prepared using the remaining future cash flows from the 2020 detailed calculations. The headrooms for 2021 do not represent the headrooms that would result if a test was run in either segment based on discounted future cash flows estimated using 2021 data and assumptions.

The key assumptions used in the value-in-use calculations are oil and natural gas prices, production volumes and the discount rate. The value-in-use calculations have been prepared solely for the purposes of determining whether the goodwill balance were impaired. Estimated future cash flows were prepared on the basis of certain assumptions prevailing at the time of the tests. 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 in either segment 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 headrooms, instead resulting in a direct impairment of the particular CGU'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 relevant goodwill headroom. It is estimated that a 33% (2020 28%) 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 oil production and operations segment. For gas & low carbon energy a 20% (2020 20%) reduction would have the same result.

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 either segment.

customers & products

										$ million
					2021					2020
	Castrol	**US Fuels**	**European Fuels**	**Other**	**Total**	Castrol	US Fuels	European Fuels	Other	Total
Goodwill	**2,837**	**606**	**862**	**392**	**4,697**	2,865	606	913	276	4,660

Cash flows for each CGU 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. It is estimated that no reasonably possible change in the key assumptions used in the US Fuels and European Fuels goodwill impairment assessments would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets.

Castrol

As permitted by IAS 36, the detailed calculations of Castrol's recoverable amount performed in the most recent detailed calculation in 2018 was used as the basis for the tests in 2021 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 Castrol 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 Castrol unit's business plan and values assigned to these key assumptions reflect past experience. A pre-tax discount rate of 9% is applied in the test. No reasonably possible change in any of these key assumptions would cause the unit's recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets. Cash flows beyond the plan period are extrapolated using a nominal 2.8% growth rate.

14. Intangible assets

						$ million
			2021			2020
	Exploration and appraisal expenditure[a]	Other intangibles	Total	Exploration and appraisal expenditure[a]	Other intangibles	Total
Cost						
At 1 January	**14,417**	**5,622**	**20,039**	15,306	4,900	20,206
Exchange adjustments	**—**	**(137)**	**(137)**	—	138	138
Acquisitions	**—**	**47**	**47**	—	318	318
Additions	**409**	**628**	**1,037**	703	645	1,348
Transfers to property, plant and equipment	**(38)**	**—**	**(38)**	(605)	—	(605)
Deletions and disposals	**(477)**	**(8)**	**(485)**	(987)	(379)	(1,366)
At 31 December	**14,311**	**6,152**	**20,463**	14,417	5,622	20,039
Amortization						
At 1 January	**10,304**	**3,642**	**13,946**	1,215	3,452	4,667
Exchange adjustments	**—**	**(86)**	**(86)**	—	93	93
Exploration expenditure written off	**167**	**—**	**167**	9,920	—	9,920
Charge for the year	**—**	**427**	**427**	—	372	372
Impairment losses	**1**	**15**	**16**	156	9	165
Deletions and disposals	**(450)**	**(8)**	**(458)**	(987)	(284)	(1,271)
At 31 December	**10,022**	**3,990**	**14,012**	10,304	3,642	13,946
Net book amount at 31 December	**4,289**	**2,162**	**6,451**	4,113	1,980	6,093
Net book amount at 1 January	**4,113**	**1,980**	**6,093**	14,091	1,448	15,539

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

15. Investments in joint ventures

The following table provides aggregated summarized financial information for the group's joint ventures 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 joint ventures - after interest and tax		Investments in joint ventures
	2021	2020	2019	2021	2020
Pan American Energy Group	**(217)**	(208)	97	**4,396**	4,613
Other joint ventures	**760**	(94)	479	**5,586**	3,749
	543	(302)	576	**9,982**	8,362

The joint venture that is material to the group at 31 December 2021 is Pan American Energy Group S.L. bp owns a 50% stake in the joint venture.

bp classifies its investment in Pan American Energy Group S.L. as a joint venture because, per the terms of the shareholders' agreement, bp has joint control over Pan American Energy Group S.L.. Pan American Energy Group S.L is based in Argentina and its functional currency is USD.

15. Investments in joint ventures – continued

The following table provides summarized financial information relating to Pan American Energy Group. This information is presented on a 100% basis and reflects adjustments made by bp to Pan American Energy Group's own results in applying the equity method of accounting. bp adjusts Pan American Energy Group's results for the accounting required under IFRS relating to bp's purchase of its interest in Pan American Energy Group S.L..

The operational and financial information of Pan American Energy Group S.L. is based on preliminary operational and financial results of Pan American Energy Group S.L. for 2021. Actual results may differ from these amounts.

			$ million
			Gross amount
	2021	2020	2019
Sales and other operating revenues	**4,394**	3,505	5,194
Profit (loss) before interest and taxation	**806**	(366)	744
Finance costs	**262**	250	154
Profit (loss) before taxation[a]	**544**	(616)	590
Taxation[b]	**978**	(200)	396
Profit (loss) for the year	**(434)**	(416)	194
Other comprehensive income	**—**	—	—
Total comprehensive income	**(434)**	(416)	194
Non-current assets	**14,206**	13,988	
Current assets[c]	**1,864**	1,885	
Total assets	**16,070**	15,873	
Current liabilities[d]	**2,034**	1,990	
Non-current liabilities[e]	**5,244**	4,657	
Total liabilities	**7,278**	6,647	
Net assets	**8,792**	9,226	
Less: non-controlling interests	**—**	—	
	8,792	9,226	

[a] Includes depreciation and amortisation of $930 million (2020 $937 million and 2019 $914 million), interest income of $19 million (2020 $18 million and 2019 $42 million) and interest expense of $262 million (2020 $250 million and 2019 $154 million).

[b] 2021 net income expense includes a deferred tax charge of $415 million related to a change in the income tax rate.

[c] Includes cash and cash equivalents of $893 million (2020 $848 million).

[d] Includes current financial liabilities of $767 million (2020 $1,282 million).

[e] Includes non-current financial liabilities of $2,132 million (2020 $1,861 million).

The group received dividends, net of withholding tax, of $nil from Pan American Energy Group S.L in 2021 (2020 $18 million and 2019 $70 million). A dividend of $18 million was declared in December 2021 and will be paid in March 2022.

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

									$ million
									bp share
			2021			2020			2019
	PAEG	**Other**	**Total**	PAEG	Other	Total	PAEG	Other	Total
Sales and other operating revenues	**2,197**	**9,048**	**11,245**	1,753	8,792	10,545	2,597	11,542	14,139
Profit (loss) before interest and taxation	**403**	**927**	**1,330**	(183)	32	(151)	372	604	976
Finance costs	**131**	**58**	**189**	125	76	201	77	32	109
Profit (loss) before taxation	**272**	**869**	**1,141**	(308)	(44)	(352)	295	572	867
Taxation	**489**	**107**	**596**	(100)	49	(51)	198	91	289
Non-controlling interest	**—**	**2**	**2**	—	1	1	—	2	2
Profit (loss) for the year	**(217)**	**760**	**543**	(208)	(94)	(302)	97	479	576
Other comprehensive income	**—**	**5**	**5**	—	(5)	(5)	—	(6)	(6)
Total comprehensive income	**(217)**	**765**	**548**	(208)	(99)	(307)	97	473	570
Non-current assets	**7,103**	**7,702**	**14,805**	6,994	5,652	12,646			
Current assets	**932**	**2,385**	**3,317**	943	2,481	3,424			
Total assets	**8,035**	**10,087**	**18,122**	7,937	8,133	16,070			
Current liabilities	**1,017**	**1,272**	**2,289**	995	1,649	2,644			
Non-current liabilities	**2,622**	**3,219**	**5,841**	2,329	2,694	5,023			
Total liabilities	**3,639**	**4,491**	**8,130**	3,324	4,343	7,667			
Net assets	**4,396**	**5,596**	**9,992**	4,613	3,790	8,403			
Less: non-controlling interests	**—**	**5**	**5**	—	39	39			
	4,396	**5,591**	**9,987**	4,613	3,751	8,364			
Group investment in joint ventures									
Group share of net assets (as above)	**4,396**	**5,591**	**9,987**	4,613	3,751	8,364			
Loans made by group companies to joint ventures	**—**	**(5)**	**(5)**	—	(2)	(2)			
	4,396	**5,586**	**9,982**	4,613	3,749	8,362			

15. Investments in joint ventures – continued

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

Sales to joint ventures	2021		2020		2019	
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	**3,923**	**292**	2,974	180	4,884	431

Purchases from joint ventures	2021		2020		2019	
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	**716**	**93**	959	84	1,812	225

In the normal course of business, bp enters into various arm's length transactions with joint ventures including fixed price commitments to sell and to purchase commodities, forward sale and purchase contracts and agency agreements.

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 reversals recognized by joint ventures in 2021 was $214 million (2020 charges of $433 million) of which $214 million (2020 $336 million) was in the oil production & operations segment.

16. Investments in associates

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

					$ million
	Income statement			Balance sheet	
	Earnings from associates - after interest and tax			Investments in associates	
	2021	2020	2019	**2021**	2020
Rosneft	**2,694**	(229)	2,295	**14,354**	11,808
Other associates	**762**	128	386	**6,647**	7,167
	3,456	(101)	2,681	**21,001**	18,975

The associate that is material to the group at both 31 December 2021 and 2020 is Rosneft.

bp owns 19.75% of the voting shares of Rosneft which are listed on the MICEX stock exchange in Moscow and its global depository receipts are listed on the London Stock Exchange. Rosneft's largest shareholder is Rosneftegaz JSC (Rosneftegaz), which is wholly owned by the Russian government. At 31 December 2021, Rosneftegaz held 40.4% (2020 40.4%) of the voting shares of Rosneft.

At 31 December 2021 and 2020 bp classified its investment in Rosneft as an associate because, in management's judgement, bp had significant influence over Rosneft; see Interests in other entities within Note 1 for further information. The group's investment in Rosneft is a foreign operation whose functional currency is the Russian rouble. The increase in the group's equity-accounted investment balance for Rosneft at 31 December 2021 compared with 31 December 2020 principally relates to earnings from Rosneft and bp's share of Rosneft's changes in equity offset by dividends.

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 share of profit or loss of Rosneft reflects its economic interest. At 31 December 2021, bp's economic interest was 22.03%.

The value of bp's 19.75% shareholding in Rosneft based on the quoted market share price of $8.04 per share (2020 $5.64 per share) was $16,827 million at 31 December 2021 (2020 $11,804 million). The value of bp's 22.03% (2020 22.03%) economic interest based on the quoted market share price was $18,773 million at 31 December 2021 (2020 $13,167 million).

See also Note 37 Events after the reporting period.

16. Investments in associates – continued

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
	2021	2020	2019
Sales and other operating revenues	118,755	82,786	134,046
Profit before interest and taxation	18,537	1,270	17,473
Finance costs	1,357	1,742	1,281
Profit (loss) before taxation	17,180	(472)	16,192
Taxation	3,209	208	3,058
Non-controlling interests	1,743	482	1,514
Profit (loss) for the year	12,228	(1,162)	11,620
Other comprehensive income	54	1,653	572
Total comprehensive income	12,282	491	12,192
Non-current assets	155,898	175,978	
Current assets	45,790	42,459	
Total assets	201,688	218,437	
Current liabilities	47,061	49,781	
Non-current liabilities	78,117	96,727	
Total liabilities	125,178	146,508	
Net assets	76,510	71,929	
Less: non-controlling interests	11,357	10,897	
	65,153	61,032	

The group received dividends, net of withholding tax, of $640 million from Rosneft in 2021 (2020 $480 million and 2019 $785 million).

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

									$ million
									bp share
			2021			2020			2019
	Rosneft	Other	Total	Rosneft	Other	Total	Rosneft[a]	Other	Total
Sales and other operating revenues	26,163	10,005	36,168	17,535	5,946	23,481	26,474	7,934	34,408
Profit before interest and taxation	4,084	1,602	5,686	295	276	571	3,451	788	4,239
Finance costs	299	73	372	372	80	452	253	87	340
Profit (loss) before taxation	3,785	1,529	5,314	(77)	196	119	3,198	701	3,899
Taxation	707	767	1,474	51	67	118	604	315	919
Non-controlling interests	384	—	384	101	1	102	299	—	299
Profit (loss) for the year	2,694	762	3,456	(229)	128	(101)	2,295	386	2,681
Other comprehensive income	12	27	39	336	(19)	317	113	(25)	88
Total comprehensive income	2,706	789	3,495	107	109	216	2,408	361	2,769
Non-current assets	34,346	9,259	43,605	33,754	11,449	45,203			
Current assets	10,088	2,418	12,506	8,238	1,749	9,987			
Total assets	44,434	11,677	56,111	41,992	13,198	55,190			
Current liabilities	10,368	1,876	12,244	9,535	1,346	10,881			
Non-current liabilities	17,210	3,298	20,508	18,558	4,709	23,267			
Total liabilities	27,578	5,174	32,752	28,093	6,055	34,148			
Net assets	16,856	6,503	23,359	13,899	7,143	21,042			
Less: non-controlling interests	2,502	—	2,502	2,091	—	2,091			
	14,354	6,503	20,857	11,808	7,143	18,951			
Group investment in associates									
Group share of net assets (as above)	14,354	6,503	20,857	11,808	7,143	18,951			
Loans made by group companies to associates	—	144	144	—	24	24			
	14,354	6,647	21,001	11,808	7,167	18,975			

[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.

16. Investments in associates – continued

Transactions between the group and its associates are summarized below.

						$ million
Sales to associates		2021		2020		2019
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	**852**	**201**	855	169	1,544	243

						$ million
Purchases from associates		2021		2020		2019
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	**7,683**	**2,072**	4,926	1,280	9,503	1,641

In the normal course of business, bp enters into various arm's length transactions with associates including fixed price commitments to sell and to purchase commodities, forward sale and purchase contracts and agency agreements.

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 $9,930 million (2020 $10,777 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 12.

bp's share of impairment charges taken by associates in 2021 was $291 million (2020 $414 million).

17. Other investments

				$ million
		2021		2020
	Current	Non-current	Current	Non-current
Equity investments[a]	—	**717**	—	913
Contingent consideration	**237**	**1,680**	317	1,682
Other	**43**	**147**	16	151
	280	**2,544**	333	2,746

[a] The majority of 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.

18. Inventories

		$ million
	2021	2020
Crude oil	**3,259**	4,498
Natural gas	**474**	265
Emissions allowances	**290**	1,297
Refined petroleum and petrochemical products	**6,638**	8,791
	10,661	14,851
Trading inventories	**11,525**	292
	22,186	15,143
Supplies	**1,525**	1,730
	23,711	16,873
Cost of inventories expensed in the income statement	**92,923**	57,682

The inventory valuation at 31 December 2021 is stated net of a provision of $432 million (2020 $584 million) to write down inventories to their net realizable value, of which $64 million (2020 $216 million) relates to hydrocarbon inventories. The net credit to the income statement in the year in respect of inventory net realizable value provisions was $153 million (2020 $17 million credit), of which $151 million credit (2020 $71 million credit) related to hydrocarbon inventories.

As a result of the changes in strategic direction of the group and the evolution of the trading strategy set out in Note 1, from 1 January 2021, certain inventory, totalling $11.4 billion as at 31 December 2021, is now treated as trading inventory and is valued at fair value whereas the equivalent inventory was previously valued at the lower of cost or net realisable value in prior periods. 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.

19. Trade and other receivables

	2021 Current	2021 Non-current	2020 Current	2020 Non-current
				$ million
Financial assets				
Trade receivables	**22,307**	**17**	12,926	19
Amounts receivable from joint ventures and associates	**404**	**89**	339	10
Receivables related to disposals[a]	**205**	**823**	1,291	2,402
Other receivables	**2,874**	**472**	2,628	637
	25,790	**1,401**	17,184	3,068
Non-financial assets				
Sales taxes and production taxes	**1,131**	**474**	557	504
Other receivables[b]	**218**	**818**	207	779
	1,349	**1,292**	764	1,283
	27,139	**2,693**	17,948	4,351

[a] For further information see Note 3 - Disposals and Impairment.

[b] Includes Gulf of Mexico oil spill trust fund reimbursement asset of $1 million (2020 $32 million).

In both 2021 and 2020 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 28 for further information.

20. Valuation and qualifying accounts

	2021 Trade and other receivables	2021 Fixed asset investments	2020 Trade and other receivables	2020 Fixed asset investments	2019 Trade and other receivables	2019 Fixed asset investments
						$ million
At 1 January	**555**	**186**	509	249	416	235
Charged to costs and expenses	**136**	**3**	214	103	206	28
Charged to other accounts[a]	**(11)**	**—**	2	—	(2)	—
Deductions	**(96)**	**(20)**	(170)	(166)	(111)	(14)
At 31 December	**584**	**169**	555	186	509	249

[a] Principally exchange adjustments.

Valuation and qualifying accounts relating to trade and other receivables comprise expected credit loss allowances. The expected credit loss allowance comprises $456 million (2020 $456 million, 2019 $414 million) relating to receivables that were credit-impaired at the end of the year and $128 million (2020 $99 million, 2019 $95 million) relating to receivables that were not credit-impaired at the end of the year. Whilst credit risk has decreased since 31 December 2020, there has also been a significant increase in the group's trade and other receivables balance. Therefore, the total expected credit loss allowances recognized as at 31 December 2021 have not significantly changed during the year.

Valuation and qualifying accounts relating to fixed asset investments comprise impairment provisions for investments in equity-accounted entities.

Valuation and qualifying accounts are deducted in the balance sheet from the assets to which they apply. For further information on the group's credit risk management policies and how the group recognizes and measures expected losses see Note 28.

21. Trade and other payables

	2021 Current	2021 Non-current	2020 Current	2020 Non-current
				$ million
Financial liabilities				
Trade payables	**37,327**	**—**	23,157	—
Amounts payable to joint ventures and associates	**2,165**	**—**	1,364	—
Payables for capital expenditure and acquisitions	**2,063**	**764**	2,297	1,033
Payables related to the Gulf of Mexico oil spill	**1,276**	**9,154**	1,399	9,988
Other payables	**5,736**	**175**	5,041	681
	48,567	**10,093**	33,258	11,702
Non-financial liabilities				
Sales taxes, customs duties, production taxes and social security	**2,708**	**77**	2,103	73
Other payables	**1,336**	**397**	653	337
	4,044	**474**	2,756	410
	52,611	**10,567**	36,014	12,112

21. Trade and other payables – continued

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 28 (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 $4,499 million payable over 11 years, $2,423 million payable over 12 years and $3,310 million payable over 11 years respectively at 31 December 2021. Reported within net cash provided by operating activities in the group cash flow statement is a net cash outflow of $1,484 million (2020 outflow of $1,786 million, 2019 outflow of $2,694 million) related to the Gulf of Mexico oil spill, which includes payments made in relation to these agreements. 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 2021 also include amounts payable for settled economic loss and property damage claims which are payable over a period of up to six years.

22. Provisions

						$ million
	Decommissioning	Environmental	Litigation and claims	Emissions	Other	Total
At 1 January 2021	**14,476**	**1,629**	**910**	**1,669**	**2,277**	**20,961**
Exchange adjustments	**(25)**	**(10)**	**(4)**	**(39)**	**(76)**	**(154)**
Increase (decrease) in existing provisions[a]	**1,231**	**363**	**226**	**2,900**	**623**	**5,343**
Write-back of unused provisions[a]	**(18)**	**(55)**	**(90)**	**(23)**	**(304)**	**(490)**
Unwinding of discount[a]	**331**	**36**	**14**	**—**	**10**	**391**
Change in discount rate	**1,252**	**41**	**33**	**—**	**6**	**1,332**
Utilization	**(72)**	**(259)**	**(188)**	**(754)**	**(642)**	**(1,915)**
Reclassified to other payables	**(257)**	**—**	**(67)**	**—**	**(16)**	**(340)**
Reclassified as liabilities directly associated with assets held for sale	**—**	**—**	**—**	**—**	**(47)**	**(47)**
Deletions	**(253)**	**—**	**—**	**—**	**—**	**(253)**
At 31 December 2021	**16,665**	**1,745**	**834**	**3,753**	**1,831**	**24,828**
Of which – current	**609**	**277**	**112**	**3,481**	**777**	**5,256**
– non-current	**16,056**	**1,468**	**722**	**272**	**1,054**	**19,572**

[a] Recognized in the Group income statement

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. Emissions provisions primarily relate to obligations under the U.S. Environmental Protection Agency Renewable Fuel Standard Program and are driven by the amount of the obligations outstanding and current price of the related credits. The provision will principally be settled through allowances already held as inventory in the group balance sheet.

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. For further information see Notes 6, 8, 19, 21, 28, 32. The litigation and claims provision presented in the table above includes 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.

23. Pensions and other post-retirement benefits

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

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

The pension obligation in the UK consists primarily of 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. This plan was closed to new joiners in 2010 and was closed to future accrual on 30 June 2021 resulting in a curtailment gain of $0.3 billion being recognized in

23. Pensions and other post-retirement benefits – continued

the income statement during the year. For active members of the plan at 30 June 2021, benefit payables are now linked to salary as at that date, rather than salary on retirement. Employees 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 2021 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 eligible retired employees and their dependants (and, in certain legacy cases, life insurance coverage); the entitlement to these benefits is based on the employee remaining in service until a specified age and completion of a minimum period of service.

In the Eurozone, there are defined benefit pension plans in Germany, France, the Netherlands and other countries. In Germany and France, the majority of the pensions are unfunded. In 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 2021 the aggregate level of contributions was $274 million (2020 $325 million and 2019 $349 million). The aggregate level of contributions in 2022 is expected to be approximately $200 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 a three year cycle a schedule of contributions is agreed covering the next five years. The schedule of contributions is next scheduled to be updated after the 31 December 2023 formal actuarial valuation. No contractually committed funding was due at 31 December 2021. The closure of the defined benefit plan to future accrual and the consequent lower service cost reduces the plan's expected future funding volatility.

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 2021 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 2021.

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 2021. 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 2020. 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[a]	**2021**	2020	2019	**2021**	2020	2019	**2021**	2020	2019
Discount rate for plan liabilities	**1.8**	1.4	2.1	**2.7**	2.2	3.1	**1.3**	1.0	1.3
Rate of increase for pensions in payment	**3.2**	2.8	2.7	**—**	—	—	**1.4**	1.3	1.5
Rate of increase in deferred pensions	**3.2**	2.8	2.7	**—**	—	—	**0.4**	0.5	0.5
Inflation for plan liabilities	**3.3**	2.9	2.7	**2.1**	1.7	1.5	**1.6**	1.5	1.7

									%
			UK			US			Eurozone
Financial assumptions used to determine benefit expense	**2021**	2020	2019	**2021**	2020	2019	**2021**	2020	2019
Discount rate for plan service cost	**1.5**	2.1	3.0	**2.4**	3.2	4.2	**1.4**	1.8	2.5
Discount rate for plan other finance expense[b]	**1.7**	2.1	2.9	**2.2**	3.1	4.1	**1.0**	1.3	2.0
Inflation for plan service cost	**2.8**	2.6	3.1	**1.7**	1.5	1.5	**1.5**	1.7	1.7

[a] Salary growth is no longer a material financial assumption for the Group following the closure of the primary pension plan to future accrual. The rate of increase in salaries for the UK was 3.6% and 3.4% in 2020 and 2019 respectively.

[b] The discount rate for plan other finance expense was 1.4% for the primary UK plan for the period before the plan closed to future accrual on 30th June 2021 and 1.9% thereafter.

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.

23. 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
	2021	2020	2019	**2021**	2020	2019	**2021**	2020	2019
Life expectancy at age 60 for a male currently aged 60	**26.9**	26.9	27.3	**24.9**	24.7	24.9	**25.8**	25.7	25.7
Life expectancy at age 60 for a male currently aged 40	**28.4**	28.4	28.9	**26.6**	26.4	26.7	**28.3**	28.2	28.3
Life expectancy at age 60 for a female currently aged 60	**28.9**	28.8	28.7	**27.9**	27.7	28.0	**29.1**	29.0	29.1
Life expectancy at age 60 for a female currently aged 40	**30.5**	30.4	30.5	**29.4**	29.2	29.7	**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. This agreement is not impacted by the closure of the plan to future accrual. There is a similar agreement in place for the primary US plan. During 2021, the UK and the US plans switched 5% and 13% of plan assets respectively from equities to bonds (2020 11% and nil% respectively).

The current asset allocation policy for the major plans at 31 December 2021 was as follows:

	UK	**US**
Asset category	**%**	**%**
Total equity (including private equity)	**12**	**27**
Bonds/cash (including LDI)	**81**	**73**
Property/real estate	**7**	**—**

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2021 were $7,399 million (2020 $4,217 million) of government-issued nominal bonds and $24,516 million (2020 $24,576 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 223.

23. Pensions and other post-retirement benefits – continued

					$ million
	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2021					
Listed equities – developed markets	**2,964**	**340**	**473**	**290**	**4,067**
– emerging markets	**252**	**45**	**67**	**76**	**440**
Private equity[c]	**3,233**	**1,537**	**—**	**3**	**4,773**
Government issued nominal bonds[d]	**7,491**	**2,606**	**974**	**432**	**11,503**
Government issued index-linked bonds[d]	**24,516**	**—**	**100**	**—**	**24,616**
Corporate bonds[d]	**10,128**	**2,475**	**689**	**498**	**13,790**
Property[e]	**2,714**	**—**	**110**	**22**	**2,846**
Cash	**1,136**	**116**	**54**	**69**	**1,375**
Other	**1,133**	**54**	**70**	**22**	**1,279**
Debt (repurchase agreements) used to fund liability driven investments	**(10,723)**	**—**	**—**	**—**	**(10,723)**
	42,844	**7,173**	**2,537**	**1,412**	**53,966**
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

[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.

23. Pensions and other post-retirement benefits – continued

$ million

	UK	US	Eurozone	Other	2021 Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	154	246	105	31	536
Past service cost[b]	(302)	—	(27)	2	(327)
Settlement[b]	—	—	(4)	(1)	(5)
Operating charge (credit) relating to defined benefit plans	(148)	246	74	32	204
Payments to defined contribution plans	76	136	7	36	255
Total operating charge (credit)	(72)	382	81	68	459
Interest income on plan assets[a]	(684)	(150)	(30)	(40)	(904)
Interest on plan liabilities	559	209	78	56	902
Other finance (income) expense	(125)	59	48	16	(2)
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	2,440	749	12	25	3,226
Change in financial assumptions underlying the present value of the plan liabilities	(100)	777	233	97	1,007
Change in demographic assumptions underlying the present value of the plan liabilities	66	(41)	(15)	1	11
Experience gains and losses arising on the plan liabilities	7	173	(11)	3	172
Remeasurements recognized in other comprehensive income	2,413	1,658	219	126	4,416
Movements in benefit obligation during the year					
Benefit obligation at 1 January	34,171	10,187	8,161	1,895	54,414
Exchange adjustments	(255)	—	(623)	(51)	(929)
Operating charge relating to defined benefit plans	(148)	246	74	32	204
Interest cost	559	209	78	56	902
Contributions by plan participants[c]	18	—	2	6	26
Benefit payments (funded plans)[d]	(1,530)	(1,192)	(87)	(164)	(2,973)
Benefit payments (unfunded plans)[d]	(8)	(268)	(288)	(21)	(585)
Disposals	—	—	(2)	—	(2)
Remeasurements	27	(909)	(207)	(101)	(1,190)
Benefit obligation at 31 December[a e]	32,834	8,273	7,108	1,652	49,867
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	41,463	7,466	2,680	1,508	53,117
Exchange adjustments	(365)	—	(214)	(28)	(607)
Interest income on plan assets[a f]	684	150	30	40	904
Contributions by plan participants[c]	18	—	2	6	26
Contributions by employers (funded plans)	134	—	115	25	274
Benefit payments (funded plans)[d]	(1,530)	(1,192)	(87)	(164)	(2,973)
Disposals	—	—	(1)	—	(1)
Remeasurements[f]	2,440	749	12	25	3,226
Fair value of plan assets at 31 December[g]	42,844	7,173	2,537	1,412	53,966
Surplus (deficit) at 31 December	10,010	(1,100)	(4,571)	(240)	4,099
Represented by					
Asset recognized	10,280	1,410	155	74	11,919
Liability recognized	(270)	(2,510)	(4,726)	(314)	(7,820)
	10,010	(1,100)	(4,571)	(240)	4,099
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	10,280	1,410	94	30	11,814
Unfunded	(270)	(2,510)	(4,665)	(270)	(7,715)
	10,010	(1,100)	(4,571)	(240)	4,099
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(32,564)	(5,763)	(2,443)	(1,382)	(42,152)
Unfunded	(270)	(2,510)	(4,665)	(270)	(7,715)
	(32,834)	(8,273)	(7,108)	(1,652)	(49,867)

[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] The past service credit in the UK represents curtailment gains arising from the closure of the primary pension plan in the UK to future accrual. Past service credits and settlements in the Eurozone include $18 million of curtailments and settlements due to restructuring initiatives. Remaining past service cost and settlements represent charges for special termination benefits reflecting the increased liability arising as a result of early retirements.

[c] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.

[d] The benefit payments amount shown above comprises $3,416 million benefits and $93 million settlements, plus $49 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for the US is made up of $6,164 million for pension liabilities and $2,109 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,405 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 221.

23. 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 221.

23. 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	—	(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

[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.

Sensitivity analysis

The discount rate, inflation 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 2021 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 2022 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 2022	**(248)**	**159**	**(57)**	**50**	**(3)**	**(6)**
Effect on obligation at 31 December 2021	**(5,143)**	**6,788**	**(951)**	**1,171**	**(980)**	**1,238**
Inflation rate[b]						
Effect on expense in 2022	**74**	**(71)**	**10**	**(8)**	**32**	**(26)**
Effect on obligation at 31 December 2021	**4,062**	**(3,912)**	**60**	**(51)**	**880**	**(748)**

[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 2022	**25**	**4**	**7**
Effect on obligation at 31 December 2021	**1,402**	**119**	**291**

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 2031 and the weighted average duration of the defined benefit obligations at 31 December 2021 are as follows:

					$ million
Estimated future benefit payments	**UK**	**US**	**Eurozone**	**Other**	**Total**
2022	**1,100**	**683**	**328**	**97**	**2,208**
2023	**1,141**	**546**	**319**	**91**	**2,097**
2024	**1,163**	**529**	**312**	**92**	**2,096**
2025	**1,164**	**527**	**312**	**92**	**2,095**
2026	**1,185**	**523**	**299**	**93**	**2,100**
2027-2031	**6,184**	**2,501**	**1,397**	**476**	**10,558**
					Years
Weighted average duration	**17.9**	**12.7**	**15.9**	**12.5**	

24. Cash and cash equivalents

		$ million
	2021	2020
Cash	**9,101**	6,235
Triparty repos and term bank deposits	**15,655**	17,368
Cash equivalents (excluding triparty repos and term bank deposits)	**5,925**	7,508
	30,681	31,111

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 2021 includes $4,740 million (2020 $1,917 million) that is restricted. The restricted cash balances include amounts required to cover initial margin on trading exchanges and certain cash balances which are subject to exchange controls.

The group holds $4,668 million (2020 $3,890 million) of cash and cash equivalents outside the UK and it is not expected that any significant tax will arise on repatriation.

25. Finance debt

						$ million
			2021			2020
	Current	Non-current	Total	Current	Non-current	Total
Borrowings	**5,557**	**55,619**	**61,176**	9,359	63,305	72,664

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 $3,366 million (2020 $8,122 million) and issued commercial paper of $2,163 million (2020 $1,004 million). Finance debt does not include accrued interest of $484 million (2020 $678 million), which is reported within other payables. As part of actively managing its debt portfolio, during the year the group bought back $11.0 billion (2020 $4.0 billion) equivalent of finance debt primarily consisting of US dollar, euro and sterling bonds. Derivatives associated with non-US dollar debt bought back were also terminated. These transactions have no significant impact on net debt and 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
						2021
US dollar	**3**	**12**	**35,891**	**2**	**25,074**	**60,965**
Other currencies	**6**	**9**	**188**	**1**	**23**	**211**
			36,079		**25,097**	**61,176**
						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

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 2021, 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
		2021		2020
	Fair value	Carrying amount	Fair value	Carrying amount
Short-term borrowings	**2,191**	**2,191**	1,237	1,237
Long-term borrowings	**60,755**	**58,985**	74,855	71,427
Total finance debt	**62,946**	**61,176**	76,092	72,664

26. 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 2021, gearing was 25.3% (2020 31.3%).

		$ million
At 31 December	2021	2020
Finance debt	**61,176**	72,664
Less: fair value asset (liability) of hedges related to finance debt[a]	**(118)**	2,612
	61,294	70,052
Less: cash and cash equivalents	**30,681**	31,111
Net debt	**30,613**	38,941
Total equity	**90,439**	85,568
Gearing	**25.3 %**	31.3 %

[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 $166 million (2020 liability of $236 million) are not included in the calculation of net debt shown above as hedge accounting was not applied for these instruments.

An analysis of changes in 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 2021	**72,664**	**(2,965)**	**9,262**	**267**	**79,228**
Exchange adjustments	**(185)**	**—**	**(215)**	**—**	**(400)**
Net financing cash flow	**(8,575)**	**(126)**	**(2,082)**	**(40)**	**(10,823)**
Fair value (gains) losses	**(2,578)**	**3,562**	**—**	**—**	**984**
New and remeasured leases/joint operation payables	**—**	**—**	**1,767**	**23**	**1,790**
Other movements	**(150)**	**10**	**(121)**	**—**	**(261)**
At 31 December 2021	**61,176**	**481**	**8,611**	**250**	**70,518**
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 operations 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

[a] Currency swaps include cross currency interest rate swaps.

The finance debt and currency swap 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 29. When hedge accounting is applied to these derivatives they are included in the calculation of net debt shown above.

27. Leases

The group leases a number of assets as part of its activities. This primarily includes drilling rigs in the oil production & operations and gas & low carbon energy segments and retail service stations, oil depots and storage tanks in the customer & products 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 (2020 8 years). Some leases 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
	2021	2020
Undiscounted lease liability cash flows due:		
Within 1 year	**1,949**	2,262
1 to 2 years	**1,631**	1,672
2 to 3 years	**1,207**	1,340
3 to 4 years	**1,005**	1,025
4 to 5 years	**682**	878
5 to 10 years	**2,089**	2,192
Over 10 years	**1,462**	1,515
	10,025	10,884
Impact of discounting	**(1,414)**	(1,622)
Lease liabilities at 31 December	**8,611**	9,262
Of which – current	**1,747**	1,933
– non-current	**6,864**	7,329

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 2021 is $4,996 million (2020 $5,309 million). The majority of this future commitment relates to the floating LNG vessel to service the Greater Tortue Ahmeyim project from 2023.

		$ million
	2021	2020
Total cash outflow for amounts included in lease liabilities[a]	**2,372**	2,779
Expense for variable payments not included in the lease liability[a]	**37**	41
Short-term lease expense[a]	**409**	621
Additions to right-of-use assets in the period	**1,807**	1,714
(Loss) gain on sale and leaseback transactions	**(1)**	187

[a] The cash outflows for amounts not included in lease liabilities approximate the income statement expenses disclosed above.

An analysis of right-of-use assets and depreciation is provided in Note 11. An analysis of lease interest expense is provided in Note 6.

28. Financial instruments and financial risk factors

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

					$ million
At 31 December 2021	Note	**Measured at amortized cost**	**Mandatorily measured at fair value through profit or loss**	**Derivative hedging instruments**	**Total carrying amount**
Financial assets					
Other investments	17	**—**	**2,824**	**—**	**2,824**
Loans		**1,045**	**232**	**—**	**1,277**
Trade and other receivables	19	**27,191**	**—**	**—**	**27,191**
Derivative financial instruments	29	**—**	**12,402**	**348**	**12,750**
Cash and cash equivalents	24	**27,107**	**3,574**	**—**	**30,681**
Financial liabilities					
Trade and other payables	21	**(58,660)**	**—**	**—**	**(58,660)**
Derivative financial instruments	29	**—**	**(13,456)**	**(465)**	**(13,921)**
Accruals		**(6,606)**	**—**	**—**	**(6,606)**
Lease liabilities	27	**(8,611)**	**—**	**—**	**(8,611)**
Finance debt	25	**(61,176)**	**—**	**—**	**(61,176)**
		(79,710)	**5,576**	**(117)**	**(74,251)**

28. Financial instruments and financial risk factors – continued

At 31 December 2020	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	17	—	3,079	—	3,079
Loans		929	369	—	1,298
Trade and other receivables	19	20,252	—	—	20,252
Derivative financial instruments	29	—	10,049	2,698	12,747
Cash and cash equivalents	24	24,905	6,206	—	31,111
Financial liabilities					
Trade and other payables	21	(44,960)	—	—	(44,960)
Derivative financial instruments	29	—	(8,320)	(82)	(8,402)
Accruals		(5,502)	—	—	(5,502)
Lease liabilities	27	(9,262)	—	—	(9,262)
Finance debt	25	(72,664)	—	—	(72,664)
		(86,302)	11,383	2,616	(72,303)

The fair value of finance debt is shown in Note 25. 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 29. 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 $627 million (2020 net gain of $367 million). Dividend income of $11 million (2020 $17 million) from investments in equity instruments classified as measured at fair value through profit or loss is presented within other income - see Note 6.

Interest income and expenses arising on financial instruments are disclosed in Note 6.

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 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 EVP trading and shipping and SVPs treasury, tax, accounting reporting control and planning & performance management. 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 chief executive officer (CEO), and via the CEO 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 trading and shipping business. 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 business. All other foreign exchange and interest rate activities within financial markets are performed within the trading and shipping business and are also underpinned by the compliance, control and risk management infrastructure common to the activities of bp's trading and shipping business. 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 trading and shipping business 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 trading and shipping business 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 trading and shipping business is responsible for delivering value across the overall crude, oil products, gas, LNG 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 and power 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 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. Trading activity occurring in liquid periods is subject to value-at-risk and other limits for each trading activity and the aggregate of all trading activity. The calculation of potential changes in value within the liquid period considers positions, historical price movements and the correlation of these price movements. Models are regularly reviewed against actual fair value movements to ensure integrity is

28. Financial instruments and financial risk factors – continued

maintained. 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. The value-at-risk measure in respect of the aggregated trading positions in liquid periods at 31 December 2021 was $100 million (2020 $40 million) whereas the average value-at-risk measure for the period was $64 million (2020 $56 million). This measure incorporates the effect of diversification reflecting the offsetting risks across the trading portfolio. Alternative measures are used to monitor exposures which are outside of 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 2021, the total foreign currency borrowings not swapped into US dollars amounted to $211 million (2020 $321 million). The group also has in issue 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 of 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. At 31 December 2021 the most significant open contracts in place were for $55 million sterling (2020 $124 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 2021 was 41% of total finance debt outstanding (2020 45%). The weighted average interest rate on finance debt at 31 December 2021 was 3% (2020 3%) and the weighted average maturity of fixed rate debt was twelve years (2020 eight 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 2022, it is estimated that the group's finance costs for 2022 would change by approximately $251 million (2020 $330 million).

bp is exposed to benchmark interest rate components; primarily 3 month USD LIBOR. From 31 December 2021 some USD LIBOR tenors, and all EUR, GBP and CHF LIBOR tenors ceased to be published. The remaining USD LIBOR tenors, including 3 month USD LIBOR, will continue to be published until June 2023.

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. Market participants have been encouraged by regulators to switch to the new risk free rates to increase market activity and liquidity as they move away from LIBOR. bp continues to monitor regulatory and market developments over the course of the transition.

During 2021, bp's internal working group for IBOR reform has continued to monitor market developments and manage transition to alternative benchmark rates. The working group has identified financial instruments that are linked to existing interest rate benchmarks, primarily, borrowings and derivative contracts. Financial instruments and relevant agreements exposed to EUR, GBP and CHF have transitioned to alternative benchmarks at 31 December 2021. As at 31 December 2021 finance debt with a carrying value of $2,062 million and derivatives with a nominal value of $24,088 million are exposed to USD LIBOR and are expected to transition to alternative benchmark rates. The derivatives comprise relevant derivative contracts hedging finance debt and hybrid bonds all of which are covered by the ISDA fallback protocol. For finance debt, negotiations with relevant counterparties are ongoing and transition is expected before the end of June 2023. Any derivatives not actively transitioned before the end of June 2023 will be transitioned through the ISDA protocol. New contracts are being executed based on the new risk free rates. The working group continues to implement the relevant IT and operational requirements needed. bp continues to participate in 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 2021 was $1,407 million (2020 $1,405 million) in respect of liabilities of joint ventures and associates and $694 million (2020 $661 million) in respect of liabilities of other third parties. Maturity dates vary, and guarantees will terminate on payment and/or cancellation of the obligation. In general, a payment under the guarantee contract would be triggered by failure of the guaranteed party to fulfil its obligation covered by the guarantee.

28. Financial instruments and financial risk factors – continued

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, treasury holds group-wide credit risk authority and oversight responsibility for exposure to banks and financial institutions.

For the purposes of financial reporting the group calculates expected loss allowances based on the maximum contractual period over which the group is exposed to credit risk. 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 2021, the group had in place credit enhancements designed to mitigate approximately $9.5 billion (2020 $5.4 billion) of credit risk of which approximately $7.5 billion (2020 $4.9 billion) related 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	**2021**	2020
AAA to AA-	**14 %**	11 %
A+ to A-	**46 %**	59 %
BBB+ to BBB-	**14 %**	8 %
BB+ to BB-	**8 %**	6 %
B+ to B-	**16 %**	13 %
CCC+ and below	**2 %**	3 %

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

28. Financial instruments and financial risk factors – continued

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

At 31 December 2021	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the balance sheet	Related amounts not set off in the balance sheet: Master netting arrangements	Related amounts not set off in the balance sheet: Cash collateral (received) pledged	Net amount
Derivative assets	**20,519**	**(7,769)**	**12,750**	**(3,104)**	**(414)**	**9,232**
Derivative liabilities	**(21,683)**	**7,769**	**(13,914)**	**3,104**	**—**	**(10,810)**
Trade and other receivables	**17,105**	**(8,104)**	**9,001**	**(1,038)**	**(249)**	**7,714**
Trade and other payables	**(19,279)**	**8,104**	**(11,175)**	**1,038**	**—**	**(10,137)**
At 31 December 2020						
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[a]	7,772	(3,679)	4,093	(823)	(122)	3,148
Trade and other payables[a]	(8,836)	3,679	(5,157)	823	—	(4,334)

[a] Certain comparative amounts have been amended to align with balance sheet presentation.

(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 utilize letter of credit (LC) facilities to mitigate credit and non-performance risk. Consequently, LCs facilitate active trading in a global market where credit and performance risk can be significant. In common with the industry, bp routinely provides LCs to some of its suppliers.

The group has committed LC facilities totalling $12,575 million (2020 $11,325 million), allowing LCs to be issued for a maximum 24-month duration. There were also uncommitted secured LC facilities in place at 31 December 2021 for $4,290 million (2020 $3,460 million), which are secured against inventories or receivables when utilized. The facilities are held with over 26 international banks. The uncommitted 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 2021, $9,154 million (2020 $5,250 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- (stable) and Moody’s Investors Service rating is A2 (stable) and the Fitch Ratings' long-term credit rating is A (stable).

During 2021, $6 billion (2020 $14 billion) of long-term taxable bonds were issued with terms ranging from twenty to forty years. In addition the group issued perpetual hybrid bonds with a US dollar equivalent value of $0.9 billion (2020 $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 $30.7 billion at 31 December 2021 (2020 $31.1 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2021, the group had substantial amounts of undrawn borrowing facilities available, consisting of an undrawn committed $8.0 billion (2020 $10.0 billion) credit facility and $4.0 billion (2020 $7.6 billion) of standby facilities. As at 31 December 2021 the credit facility and standby facilities were available for two and four years respectively. The facilities are with 27 international banks and borrowings under them would be at pre-agreed rates. In February 2022 these facilities were extended for a further year.

For further information on the group's sources and uses of cash see Liquidity and capital resources on page 342.

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

28. Financial instruments and financial risk factors – continued

The table below shows the timing of undiscounted 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.

								$ million
				2021				2020
	Trade and other payables[a]	Accruals	Finance debt	Interest on finance debt	Trade and other payables[a]	Accruals	Finance debt	Interest on finance debt
Within one year	**48,497**	**5,638**	**5,370**	**1,497**	33,290	4,650	9,119	1,778
1 to 2 years	**1,627**	**209**	**4,425**	**1,341**	1,728	157	6,292	1,477
2 to 3 years	**1,346**	**108**	**5,953**	**1,204**	1,590	184	7,031	1,305
3 to 4 years	**1,328**	**144**	**5,958**	**1,047**	1,332	87	8,047	1,110
4 to 5 years	**1,146**	**56**	**5,504**	**896**	1,335	217	6,652	919
5 to 10 years	**5,695**	**218**	**16,483**	**2,705**	4,570	108	22,156	2,408
Over 10 years	**1,699**	**233**	**14,744**	**1,699**	4,419	99	10,008	1,037
	61,338	**6,606**	**58,437**	**10,389**	48,264	5,502	69,305	10,034

[a] 2021 includes $13,170 million (2020 $14,569 million) in relation to the Gulf of Mexico oil spill, of which $11,883 million (2020 $13,160 million) matures in greater than one year.

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 $27,048 million at 31 December 2021 (2020 $33,704 million) to be received on the same day as the related cash outflows.

		$ million
Cash outflows for derivative financial instruments at 31 December	2021	2020
Within one year	**1,497**	2,384
1 to 2 years	**1,492**	1,976
2 to 3 years	**2,531**	2,017
3 to 4 years	**2,053**	3,074
4 to 5 years	**5,575**	2,582
5 to 10 years	**8,618**	15,263
Over 10 years	**5,365**	4,483
	27,131	31,779

For further information on our derivative financial instruments, see Note 29.

29. Derivative financial instruments

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

For information on significant estimates and judgements made in relation to the 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, forwards and physical commodity sale and purchase contracts are generally valued using readily available information in the public markets and quotations provided by brokers and price index developers. These quotes are corroborated with market data and are categorized within level 2 of the fair value hierarchy.

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

29. Derivative financial instruments – continued

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

				$ million
		2021		2020
	Fair value asset	Fair value liability	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	272	(643)	858	(694)
Oil price derivatives	2,192	(1,567)	1,519	(1,093)
Natural gas price derivatives	6,823	(8,273)	6,406	(5,489)
Power price derivatives	3,105	(2,966)	1,258	(1,037)
Other derivatives	10	—	7	—
	12,402	(13,449)	10,048	(8,313)
Embedded derivatives				
Other embedded derivatives	—	(7)	1	(7)
	—	(7)	1	(7)
Cash flow hedges				
Currency forwards	1	—	4	—
Gas price futures	—	—	—	—
	1	—	4	—
Fair value hedges				
Currency swaps	326	(465)	2,614	(82)
Interest rate swaps	21	—	80	—
	347	(465)	2,694	(82)
	12,750	(13,921)	12,747	(8,402)
Of which – current	5,744	(7,565)	2,992	(2,998)
– non-current	7,006	(6,356)	9,755	(5,404)

Derivatives held for trading

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

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

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

							$ million
							2021
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	168	52	1	1	—	50	272
Oil price derivatives	1,544	429	167	47	4	1	2,192
Natural gas price derivatives	2,678	847	547	456	368	1,927	6,823
Power price derivatives	1,322	553	285	174	124	647	3,105
Other derivatives	—	7	—	—	—	3	10
	5,712	1,888	1,000	678	496	2,628	12,402

							$ 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

29. Derivative financial instruments – continued

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

							$ million
							2021
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**(191)**	**(2)**	**(13)**	**(5)**	**(173)**	**(259)**	**(643)**
Oil price derivatives	**(1,340)**	**(179)**	**(39)**	**(7)**	**(2)**	**—**	**(1,567)**
Natural gas price derivatives	**(4,551)**	**(1,053)**	**(460)**	**(351)**	**(282)**	**(1,576)**	**(8,273)**
Power price derivatives	**(1,485)**	**(601)**	**(211)**	**(135)**	**(92)**	**(442)**	**(2,966)**
	(7,567)	**(1,835)**	**(723)**	**(498)**	**(549)**	**(2,277)**	**(13,449)**

							$ million
							2020
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
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)

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

							$ million
							2021
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Fair value of derivative assets							
Level 1	**63**	**25**	**4**	**6**	**1**	**—**	**99**
Level 2	**11,418**	**1,957**	**631**	**298**	**139**	**102**	**14,545**
Level 3	**888**	**600**	**510**	**416**	**382**	**2,731**	**5,527**
	12,369	**2,582**	**1,145**	**720**	**522**	**2,833**	**20,171**
Less: netting by counterparty	**(6,657)**	**(694)**	**(145)**	**(42)**	**(26)**	**(205)**	**(7,769)**
	5,712	**1,888**	**1,000**	**678**	**496**	**2,628**	**12,402**
Fair value of derivative liabilities							
Level 1	**(57)**	**(28)**	**(4)**	**(8)**	**(2)**	**—**	**(99)**
Level 2	**(13,646)**	**(2,189)**	**(575)**	**(251)**	**(305)**	**(216)**	**(17,182)**
Level 3	**(521)**	**(312)**	**(289)**	**(281)**	**(268)**	**(2,266)**	**(3,937)**
	(14,224)	**(2,529)**	**(868)**	**(540)**	**(575)**	**(2,482)**	**(21,218)**
Less: netting by counterparty	**6,657**	**694**	**145**	**42**	**26**	**205**	**7,769**
	(7,567)	**(1,835)**	**(723)**	**(498)**	**(549)**	**(2,277)**	**(13,449)**
Net fair value	**(1,855)**	**53**	**277**	**180**	**(53)**	**351**	**(1,047)**

							$ million
							2020
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of derivative assets							
Level 1	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

29. Derivative financial instruments – continued

Level 3 derivatives

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

						$ million
	Oil price	**Natural gas price**	**Power price**	**Currency**	**Other**	**Total**
Fair value contracts at 1 January 2021	**191**	**147**	**(173)**	**5**	**6**	**176**
Gains (losses) recognized in the income statement	**302**	**410**	**407**	**(159)**	**1**	**961**
Purchases	**—**	**—**	**—**	**—**	**3**	**3**
Settlements	**(248)**	**(33)**	**(115)**	**—**	**—**	**(396)**
Transfers out of level 3	**(46)**	**10**	**(79)**	**—**	**—**	**(115)**
Net fair value of contracts at 31 December 2021	**199**	**534**	**40**	**(154)**	**10**	**629**
Deferred day-one gains (losses)						**961**
Derivative asset (liability)						**1,590**

						$ million
	Oil price	Natural gas price	Power price	Currency	Other	Total
Fair value contracts at 1 January 2020	71	28	(125)	—	110	84
Gains (losses) recognized in the income statement	250	184	162	5	(71)	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)	5	6	176
Deferred day-one gains (losses)						881
Derivative asset (liability)						1,057

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2021 was a $755 million gain (2020 $315 million gain related to derivatives still held at 31 December 2020).

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 $4,466 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. The change in the unrealized value of these contracts was a net loss of $775 million (2020 $829 million net gain and 2019 $160 million net gain). Where the derivative is economically hedging finance debt, gains and losses on such derivative contracts are included within finance costs in 2021 and in production and manufacturing expenses in previous periods. Where the derivative is managing non-US hybrid bond exposure gains and loss are included within production and manufacturing expenses. 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 2021, the group held currency forwards designated as hedging instruments in cash flow hedge relationships of highly probable forecast non-US dollar capital expenditure. Note 28 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

29. 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. 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 2021			
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	**(1)**	**1**	**—**
Commodity price risk			
Highly probable forecast sales	**(430)**	**430**	**—**
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)	—

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 2021	**$ million**	**$ million**	**$ million**	**mmBtu**
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	**1**	**—**	**55**	
Commodity price risk				
Highly probable forecast sales	**—**	**—**		**(420)**
At 31 December 2020				
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	4	—	162	
Commodity price risk				
Highly probable forecast sales	—	—		(175)

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

29. Derivative financial instruments – continued

All of the nominal amount of hedging instruments at 31 December 2021 and 2020 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 2021 relating to highly probably forecast sales 245 mmBtu (2020 135 mmBtu) matures within 12 months and 175 mmBtu (2020 40 mmBtu) within one to two years.

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			
	2021		2020	
At 31 December	Forecast capital expenditure	Forecast sales	Forecast capital expenditure	Forecast sales
Sterling/US dollar	1.33		1.35	
Korean won/US dollar	—		1,174.47	
Henry Hub $/mmBtu		3.24		2.88

Fair value hedges

At 31 December 2021, 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 28 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 interest rate benchmark reform. The group's swaps which reference interest rates are primarily exposed to 3 month USD LIBOR. For all of the swaps that reference Inter-Bank Offered Rates (IBORs), ISDA fallback clauses to amend derivatives on the cessation of LIBOR are already available as bp and its counterparties have adhered to the protocol. 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. The interest rate benchmark reform does not change the risk management strategy for fair value hedges.

Uncertainty around the method and timing of transition from 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.

The reliefs above will continue to apply until the uncertainty arising from the interest benchmark reform with respect to the timing and amount of the underlying cash flows to which the group is exposed ends. The group expects this uncertainty to continue until either the ISDA fallback clauses are activated in June 2023 or the contracts that reference IBORs are modified replacing the IBOR benchmark rate with a risk free rate. The group's assumption is that any modifications to swaps will meet the 'economically equivalent' criteria with contractual changes restricted to only those changes necessary to replace the benchmark rate with a risk free rate.

At 31 December 2021 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.

29. Derivative financial instruments – continued

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 26.

			$ million
At 31 December 2021	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	**54**	**(54)**	**—**
Interest rate and foreign currency risk on finance debt	**2,565**	**(2,460)**	**(105)**
At 31 December 2020			
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

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 2021	Assets	Liabilities	
Fair value hedges			
Interest rate risk on finance debt	**21**	**—**	**1,102**
Interest rate and foreign currency risk on finance debt	**326**	**(465)**	**18,880**
At 31 December 2020			
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

All hedging instruments are presented within derivative financial instruments on the group balance sheet. In 2021 ineffectiveness arising on fair value hedges is included within finance costs in the income statement. In 2020 ineffectiveness arising on fair value hedges was 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 2021	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	**713**	**—**	**219**	**—**	**170**	**—**	**—**	**1,102**
Interest rate and foreign currency risk on finance debt	**715**	**1,426**	**2,377**	**2,114**	**2,400**	**4,471**	**5,377**	**18,880**
At 31 December 2020								
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

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		2021		2020
	Interest rate swaps	Cross-currency interest rate swaps	Interest rate swaps	Cross-currency interest rate swaps
Interest rate	**0.31 %**	**1.91 %**	0.58 %	1.88 %
Sterling/US dollar		**1.36**		1.33
Euro/US dollar		**1.13**		1.14
Canadian dollar/US dollar		**0.78**		0.78

29. Derivative financial instruments – continued

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 2021	Assets	Liabilities	Assets	Liabilities	Discontinued hedges
Fair value hedges					
Interest rate risk on finance debt	**—**	**(1,170)**	**—**	**(22)**	**(524)**
Interest rate and foreign currency risk on finance debt	**—**	**(18,837)**	**—**	**(94)**	**—**

At 31 December 2020					
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)	—

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

Movement in reserves related to hedge accounting

The table below provides a reconciliation of the cash flow hedge and costs of hedging reserves on a pre-tax basis by risk category. The signage convention of this table is consistent with that presented in Note 31.

					$ 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 2021	**12**	**41**	**(651)**	**(106)**	**(704)**
Recognized in other comprehensive income					
Cash flow hedges marked to market	**1**	**(430)**	**—**	**—**	**(429)**
Cash flow hedges reclassified to the income statement - hedged item affected profit or loss	**—**	**255**	**—**	**—**	**255**
Costs of hedging marked to market	**—**	**—**	**—**	**(105)**	**(105)**
Costs of hedging reclassified to the income statement	**—**	**—**	**—**	**21**	**21**
	1	**(175)**	**—**	**(84)**	**(258)**
Cash flow hedges transferred to the balance sheet	**(10)**	**—**	**—**	**—**	**(10)**
At 31 December 2021	**3**	**(134)**	**(651)**	**(190)**	**(972)**

					$ 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)

[a] See Note 31 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.

30. Called-up share capital

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

	2021		2020		2019	
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	**21,449,782**	**5,362**	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	**35,001**	**9**	34,000	9	37,400	9
Repurchase of ordinary share capital	**(706,701)**	**(177)**	(120,058)	(30)	(235,951)	(59)
At 31 December	**20,778,082**	**5,194**	21,449,782	5,362	21,535,840	5,383
		5,215		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 2021 the company repurchased 707 million ordinary shares for a total consideration of $3,151 million, including transaction costs of $17 million, as part of the share repurchase programme announced on 27 April 2021. All shares purchased were for cancellation. The repurchased shares represented 3.4% of ordinary share capital. The number of shares in issue is reduced when shares are repurchased. As of 1 March 2022, the latest practicable date before the completion of these financial statements, 288 million further ordinary shares were repurchased for cancellation for a total cost of $1,535 million, including transaction costs of $8 million.

Treasury shares[a]

	2021		2020		2019	
	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,187,650**	**296**	1,296,856	323	1,426,265	356
Purchases for settlement of employee share plans	**1,432**	**—**	—	—	1,118	—
Issue of new shares for employee share-based payment plans	**35,096**	**9**	34,116	9	37,400	9
Shares re-issued for employee share-based payment plans	**(86,721)**	**(22)**	(143,322)	(36)	(167,927)	(42)
At 31 December	**1,137,457**	**283**	1,187,650	296	1,296,856	323
Of which – shares held in treasury by bp	**1,037,201**	**259**	1,105,157	275	1,163,077	290
– shares held in ESOP trusts	**100,256**	**24**	82,491	21	133,707	33
– shares held by bp's US share plan administrator[b]	**—**	**—**	2	—	72	—

[a] See Note 31 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 5.2% (2020 5.4% and 2019 5.9%) of the called-up ordinary share capital of the company.

During 2021, the movement in shares held in treasury by bp represented less than 0.3% (2020 less than 0.3% and 2019 less than 0.5%) of the ordinary share capital of the company.

31. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2021	**5,383**	**12,584**	**1,528**	**27,206**	**46,701**
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	**(177)**	—	**177**	—	—
Share-based payments, net of tax[b]	**9**	**161**	—	—	**170**
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
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 2021	**5,215**	**12,745**	**1,705**	**27,206**	**46,871**
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

[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] 2021 principally relates to the sale of 49% interest in a controlled affiliate holding certain refined product and crude logistics assets onshore US and the buy-out of the non-controlling interest in the Thorntons fuels and convenience retail business. 2020 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.

31. Capital and reserves – continued

$ million

Treasury shares	Foreign currency translation reserve	Cash flow hedges	Costs of hedging	Total fair value reserves	Profit and loss account	bp shareholders' equity	Non-controlling interests Hybrid bonds	Non-controlling interests Other interest	Total equity
(13,224)	**(8,719)**	**(708)**	**(100)**	**(808)**	**47,300**	**71,250**	**12,076**	**2,242**	**85,568**
—	**—**	**—**	**—**	**—**	**7,565**	**7,565**	**507**	**415**	**8,487**
—	**(846)**	**—**	**—**	**—**	**—**	**(846)**	**—**	**(24)**	**(870)**
—	**—**	**(134)**	**(76)**	**(210)**	**—**	**(210)**	**—**	**—**	**(210)**
—	**—**	**—**	**—**	**—**	**44**	**44**	**—**	**—**	**44**
—	**—**	**—**	**—**	**—**	**1**	**1**	**—**	**—**	**1**
—	**—**	**—**	**—**	**—**	**3,099**	**3,099**	**—**	**—**	**3,099**
—	**—**	**1**	**—**	**1**	**—**	**1**	**—**	**—**	**1**
—	**(846)**	**(133)**	**(76)**	**(209)**	**10,709**	**9,654**	**507**	**391**	**10,552**
—	**—**	**—**	**—**	**—**	**(4,316)**	**(4,316)**	**—**	**(311)**	**(4,627)**
—	**—**	**(10)**	**—**	**(10)**	**—**	**(10)**	**—**	**—**	**(10)**
—	**—**	**—**	**—**	**—**	**(3,151)**	**(3,151)**	**—**	**—**	**(3,151)**
600	**—**	**—**	**—**	**—**	**(138)**	**632**	**—**	**—**	**632**
—	**—**	**—**	**—**	**—**	**556**	**556**	**—**	**—**	**556**
—	**—**	**—**	**—**	**—**	**(26)**	**(26)**	**950**	**—**	**924**
—	**(7)**	**—**	**—**	**—**	**—**	**(7)**	**(492)**	**—**	**(499)**
—	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
—	**—**	**—**	**—**	**—**	**881**	**881**	**—**	**(387)**	**494**
(12,624)	**(9,572)**	**(851)**	**(176)**	**(1,027)**	**51,815**	**75,463**	**13,041**	**1,935**	**90,439**
(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

31. Capital and reserves – continued

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 31 December 2018	5,402	12,305	1,439	27,206	46,352
Adjustment on adoption of IFRS 16, net of tax	—	—	—	—	—
At 1 January 2019	5,402	12,305	1,439	27,206	46,352
Profit (loss) for the year	—	—	—	—	—
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications)	—	—	—	—	—
Cash flow hedges and costs of hedging (including reclassifications)	—	—	—	—	—
Share of items relating to equity-accounted entities, net of tax[a]	—	—	—	—	—
Other	—	—	—	—	—
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	—	—	—	—
Cash flow hedges that will subsequently be transferred to the balance sheet	—	—	—	—	—
Total comprehensive income	—	—	—	—	—
Dividends	52	(52)	—	—	—
Cash flow hedges transferred to the balance sheet, net of tax	—	—	—	—	—
Repurchases of ordinary share capital	(59)	—	59	—	—
Share-based payments, net of tax[b]	9	164	—	—	173
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
Transactions involving non-controlling interests, net of tax[c]	—	—	—	—	—
At 31 December 2019	5,404	12,417	1,498	27,206	46,525

[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 the sale of a 49% interest in bp's retail property portfolio in Australia.

31. Capital and reserves – continued

$ million

Treasury shares	Foreign currency translation reserve	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	
(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

31. Capital and reserves – continued

Share capital

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

Share premium account

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

Capital redemption reserve

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

Merger reserve

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

Treasury shares

Treasury shares represent bp shares repurchased and available for specific and limited purposes. For accounting purposes shares held in Employee Share Ownership Plans (ESOPs) 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. It includes approximately $11 billion loss relating to the investment in Rosneft which is now expected to be reclassified to the income statement in 2022. See Note 37 Events after the reporting period.

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 is now expected to be reclassified to the income statement in 2022. See Note 37 Events after the reporting period. 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. 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. Payments made to and profit attributed to these hybrid bond holders in the year totalled $499 million (2020 $89 million) and $497 million (2020 $256 million) respectively. The accumulated non-controlling interest at the end of the year was $12,081 million (2020 $12,076 million).

Non-controlling interests also includes perpetual subordinated hybrid securities issued during 2021 by a group subsidiary, of $950 million. The proceeds from this issuance were specifically earmarked to fund the forward purchase and leaseback of an under-construction floating, production, storage, and offloading vessel (FPSO) to be used on one of the group's major projects. The contractual terms of these instruments allow the group to defer interest payments and repayment of principle indefinitely however their terms and conditions stipulate that the group must purchase them on the occurrence of certain events, all within the group's control, including the declaration or payment of a BP p.l.c. distribution after mid-May 2026. The accumulated non-controlling interest at the end of the year was $960 million, including $10 million of profit attributable to holders.

As the group has the unconditional right to avoid transferring cash or another financial asset in relation to these hybrid bonds and securities, they are classified as equity instruments and reported within non-controlling interests in the consolidated financial statements.

31. Capital and reserves – continued

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

			$ million
			2021
	Pre-tax	**Tax**	**Net of tax**
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	**(885)**	**15**	**(870)**
Cash flow hedges (including reclassifications)	**(175)**	**41**	**(134)**
Costs of hedging (including reclassifications)	**(84)**	**8**	**(76)**
Share of items relating to equity-accounted entities, net of tax	**44**	**—**	**44**
Other	**—**	**1**	**1**
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	**4,416**	**(1,317)**	**3,099**
Cash flow hedges that will subsequently be transferred to the balance sheet	**1**	**—**	**1**
Other comprehensive income	**3,317**	**(1,252)**	**2,065**

			$ 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

32. Contingent liabilities and legal proceedings

Contingent liabilities

There were contingent liabilities at 31 December 2021 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 28.

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.

32. 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 production and manufacturing 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. The group estimates that for production facilities, approximately $13 billion of associated decommissioning obligations were previously transferred to third parties. While the amounts associated with decommissioning provisions reverting to the group 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 the owner of facilities has agreed to relinquish all of its assets to the U.S. government upon liquidation to resolve the outstanding liability. It is considered possible that certain decommissioning costs associated with some of these facilities in relation to assets previously disposed may in the future revert to bp; however, no provision has been recognized as no present obligation exists at the balance sheet date. Should the obligation revert, it 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 customers & products facilities are not generally recognized as the potential obligations cannot be measured given their indeterminate settlement dates.

By their nature, it is not practicable to estimate the potential financial impact or possible timing of the above contingencies as there are significant uncertainties that are dependent on various factors that are not within the group's control.

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 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
Following orders issued by United States District Court for the Eastern District of Louisiana on 22 January 2021, the claims administrator pursuant to the settlement programme which was established by the Economic and Property Damages Settlement has completed post-closure administrative wind down activities and the administration website has been closed.

Medical Benefits Class Action Settlement
In 2012 the Medical Benefits Class Action Settlement (Medical Settlement) was entered into with the plaintiffs steering committee. 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. All SPC claims have been determined by the medical claims administrator. 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 9,624 claims have been denied.

The Medical Settlement also includes an exclusive remedy provision regarding class members pursuing exposure-based personal injury 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 four years after the date of first diagnosis of the LMPC. As of 31 December 2021, there were 199 pending lawsuits brought by class members claiming LMPCs.

Other civil complaints – economic loss
All but one of the 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.

One appeal remains pending before the Fifth Circuit by a plaintiff whose economic loss claims were dismissed by an August 2021 order from the federal district court in New Orleans that granted bp's motion for summary judgment.

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 early April 2021, the federal district court in New Orleans severed nearly all of the remaining post-explosion clean-up, medical monitoring and personal injury cases from the consolidated multi-district proceedings. Of those severed cases, 19 are pending before other federal courts in Gulf Coast States, and the remaining 777 cases have been re-allotted among the judges of the federal district court in the Eastern District of Louisiana. 9 post-explosion clean-up, medical monitoring and personal injury cases will remain in the consolidated multi-district proceedings until plaintiffs have complied with the court's pre-trial orders, after which they will be severed from the consolidated multi-district proceedings.

32. Contingent liabilities and legal proceedings – continued

Non-US government lawsuits

On 18 October 2012, a group of Mexican fishermen filed a class action complaint in a Mexican Federal District Court located in Mexico City against BP America Production Company (BPAPC) and other bp subsidiaries, seeking to recover for alleged environmental and economic harm in Mexico as a result of the Incident. 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 subsequent material development in these proceedings.

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 any person or entity harmed by the Incident, including several coastal Mexican states and municipalities 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. That challenge was denied on 8 October 2020 and on 18 January 2021, bp's appeal of that ruling was also denied. On 27 December 2019, the court issued an order on class notification procedures. On 2 January 2020, ACS moved for reconsideration of the order on class notification procedures, which was denied on 26 October 2021. On 22 November 2021, ACS filed a constitutional challenge to the notice ruling. A decision on the constitutional challenge is pending.

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 filed an appeal with the US Court of Appeals. Oral arguments were heard by the Fifth Circuit in early 2022 and a decision is expected later this year.

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. Underlying many of the legal theories are allegations regarding deceptive communication and disinformation to the public. The lawsuits 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.

33. Remuneration of senior management and non-executive directors

Remuneration of directors

			$ million
	2021	2020	2019
Total for all directors			
Emoluments	**9**	6	9
Amounts received under incentive schemes[a]	**4**	14	20
Total	**13**	20	29

[a] Excludes amounts relating to past directors.

Emoluments

These amounts comprise fees paid to the non-executive chair 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

Full details of individual directors' remuneration are given in the Directors' remuneration report on page 116. See also Related-party transactions on page 361.

Remuneration of directors and senior management

			$ million
	2021	2020	2019
Total for all senior management and non-executive directors			
Short-term employee benefits	**30**	17	30
Pensions and other post-retirement benefits	**1**	2	2
Share-based payments	**32**	52	32
Termination benefits	**–**	8	—
Total	**63**	79	64

Senior management comprises members of the leadership team, see pages 88-89 for further information.

Short-term employee benefits

These amounts comprise fees and benefits paid to the non-executive chair 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.

34. Employee costs and numbers

Employee costs	2021	2020	$ million 2019
Wages and salaries[a]	**6,934**	7,600	7,497
Social security costs	**733**	729	733
Share-based payments[b]	**733**	728	694
Pension and other post-retirement benefit costs	**457**	852	948
	8,857	9,909	9,872

			2021			2020			2019
Average number of employees[c d]	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
gas & low carbon energy	**400**	**3,400**	**3,800**						
oil production & operations	**3,100**	**6,000**	**9,100**						
customers & products[e]	**6,200**	**35,800**	**42,000**						
other businesses and corporate[f]	**1,400**	**7,700**	**9,100**						
	11,100	**52,900**	**64,000**	12,400	55,700	68,100	13,600	58,900	72,500

[a] Includes termination costs of $74 million (2020 $1,237 million and 2019 $182 million).

[b] The group provides certain employees with shares and share options as part of their remuneration packages. The majority of these share-based payment arrangements are equity-settled.

[c] Reported to the nearest 100.

[d] Information for 2021 has been presented to reflect the changes in reportable segments. For more information see Note 1 Significant accounting policies, judgements, estimates and assumptions - Change in segmentation. Comparative data for these new reportable segments for 2020 and 2019 is not available.

[e] Includes 21,300 (2020 19,100 and 2019 18,100) service station staff.

[f] Includes 0 (2020 0 and 2019 2,500) agricultural, operational and seasonal workers in Brazil.

The reduction in the average number of employees in 2021 compared to 2020 is principally a result of the reinvent bp programme.

35. Auditor's remuneration

Fees	2021	2020	$ million 2019
The audit of the company annual accounts[a]	**37**	30	32
The audit of accounts of subsidiaries of the company	**15**	11	11
Total audit	**52**	41	43
Audit-related assurance services[b]	**5**	11	4
Total audit and audit-related assurance services	**57**	52	47
Non-audit and other assurance services	**—**	1	1
Services relating to bp pension plans	**1**	1	1
	58	54	49

[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).

2021 includes $1.0 million of additional fees for 2020. 2020 includes $0.5 million of additional fees for 2019. 2019 includes $3.6 million of additional fees for 2018. 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 2021 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 $58 million (2020 $54 million and 2019 $49 million) is required to be presented as follows: audit $52 million (2020 $41 million and 2019 $43 million); other audit-related $5 million (2020 $11 million and 2019 $4 million); tax $nil (2020 $nil and 2019 $nil); and all other fees $1 million (2020 $2 million and 2019 $2 million).

36. Subsidiaries, joint arrangements and associates

The more important subsidiaries, joint arrangements and associates of the group at 31 December 2021 and the group percentage of ordinary share capital (to nearest whole number) are set out below. 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 Limited	100	England & Wales	Investment holding
BP Exploration Operating Company Limited	100	England & Wales	Exploration and production
*BP Global Investments Limited	100	England & Wales	Investment holding
*BP International Limited	100	England & Wales	Integrated oil operations
BP Oil International Limited	100	England & Wales	Integrated oil operations
*Burmah Castrol PLC	100	Scotland	Lubricants
Angola			
BP Exploration (Angola) Limited	100	England & Wales	Exploration and production
Azerbaijan			
BP Exploration (Caspian Sea) Limited	100	England & Wales	Exploration and production
BP Exploration (Azerbaijan) Limited	100	England & Wales	Exploration and production
Canada			
*BP Holdings Canada Limited	100	England & Wales	Investment holding
Egypt			
BP Exploration (Delta) Limited	100	England & Wales	Exploration and production
Germany			
BP Europa SE	100	Germany	Refining and marketing
India			
BP Exploration (Alpha) Limited	100	England & Wales	Exploration and production
Trinidad & Tobago			
BP Trinidad and Tobago LLC	70	US	Exploration and production
UK			
BP Capital Markets p.l.c.	100	England & Wales	Finance
US			
*BP Holdings North America Limited	100	England & Wales	Investment holding
Atlantic Richfield Company	100	US	Exploration and production, refining and marketing
BP America Inc.	100	US	
BP America Production Company	100	US	
BP Company North America Inc.	100	US	
BP Corporation North America Inc.	100	US	
BP Products North America Inc.	100	US	
The Standard Oil Company	100	US	
BP Capital Markets America Inc.	100	US	Finance

Joint arrangements	%	Country of incorporation	Principal activities
Argentina			
Pan American Energy Group S.L.	50	Spain	Integrated oil operations

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

[a] See Note 37 Events after the reporting period.

37. Events after the reporting period

On 27 February 2022, following the military action in Ukraine, bp announced that bp it will exit its 19.75% shareholding in Rosneft Oil Company (Rosneft) a Russian oil and gas company. As of 27 February 2022, bp chief executive officer Bernard Looney also stepped down from the board of Rosneft with immediate effect and has submitted a letter of resignation as did the other Rosneft director nominated by bp, former bp group chief executive Bob Dudley.

As a result of bp's nominated directors stepping down from the Rosneft board, bp has determined that as of 27 February 2022, the group no longer has significant influence over Rosneft taking into account the criteria set out in IAS 28 Investments in Associates and Joint Ventures, bp will therefore no longer equity account for its interest in Rosneft as of that date, treating the investment prospectively as a financial asset measured at fair value within 'Other investments' until the shareholding is derecognized.

Additionally, in response to sanctions imposed on Russia by a number of countries, Russia has implemented new counter-sanctions including restrictions on the divestment from Russian assets by foreign investors and a reported temporary prohibition on registrars and depositories from making payments on Russian securities in favour of foreign investors. Further details including confirmation of the precise terms or application of these counter-sanctions are not yet known.

The discontinuation of equity accounting combined with the market impact on Russian assets that has arisen following the military action in Ukraine will have a material effect on the group's first quarter 2022 interim financial statements including on the carrying amount of bp's investment in Rosneft, which at 31 December 2021 stood at approximately $14 billion. In addition, foreign exchange losses and other cumulative charges to other comprehensive income will be taken to the income statement. At 31 December 2021, these amounts stood at approximately $11 billion. The change in accounting treatment also means that bp will no longer recognize a share in Rosneft's net income, production and reserves from 27 February 2022. The group will cease to report Rosneft as a separate segment in the group's financial reporting for 2022.

Also, as of 27 February 2022, bp decided to exit its other businesses with Rosneft within Russia, the carrying value of which stood at $1.4 billion at 31 December 2021. The associated impacts will also be reflected in the group's first quarter 2022 interim financial statements.

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[a]), 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 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 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 348-353.

[a] See Note 37 Events after the reporting period.

Oil and natural gas exploration and production activities

										$ million
										2021
	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	30,285	—	62,157	3,385	16,351	51,157		45,767	6,641	215,743
Unproved properties	363	—	2,888	2,650	2,517	3,553		1,690	650	14,311
	30,648	—	65,045	6,035	18,868	54,710	—	47,457	7,291	230,054
Accumulated depreciation	21,293	—	34,151	5,008	14,393	46,187		26,607	4,617	152,256
Net capitalized costs	9,355	—	30,894	1,027	4,475	8,523	—	20,850	2,674	77,798
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	—	—	81	—	—	—	—	—	—	81
Unproved	—	—	18	—	—	—	—	—	—	18
	—	—	99	—	—	—		—	—	99
Exploration and appraisal costs[c]	28	—	138	88	90	85	—	159	18	606
Development[d]	262	—	2,541	(50)	586	1,246	—	1,849	162	6,596
Total costs	290	—	2,778	38	676	1,331	—	2,008	180	7,301
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[e]										
Third parties	182	—	1,700	384	1,330	2,934	2	2,469	994	9,995
Sales between businesses	3,204	—	9,034	1	321	2,172	—	7,064	743	22,539
	3,386	—	10,734	385	1,651	5,106	2	9,533	1,737	32,534
Exploration expenditure	76	—	78	90	29	84	—	52	15	424
Production costs	653	—	1,953	121	371	781	—	967	121	4,967
Production taxes	(35)	—	108	—	266	—	—	918	51	1,308
Other costs (income)[f]	170	(2)	2,506	35	50	121	37	(12)	139	3,044
Depreciation, depletion and amortization	1,260	—	3,153	83	524	2,897	2	2,190	332	10,441
Net impairments and (gains) losses on sale of businesses and fixed assets	(755)	(124)	(1,599)	1,075	(693)	750	—	(2,762)	(1)	(4,109)
	1,369	(126)	6,199	1,404	547	4,633	39	1,353	657	16,075
Profit (loss) before taxation[g]	2,017	126	4,535	(1,019)	1,104	473	(37)	8,180	1,080	16,459
Allocable taxes	302	1	1,127	171	696	363	—	3,055	404	6,119
Results of operations	1,715	125	3,408	(1,190)	408	110	(37)	5,125	676	10,340

[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] Development costs in Rest of North America are negative due to a true-up of prior period spend.

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

[f] Includes property taxes and other government take. The UK region includes a $213-million gain which is offset by corresponding charges primarily in the US region, relating to the group self-insurance programme.

[g] Excludes the unwinding of the discount on provisions and payables amounting to $325-million which is included in finance costs in the group income statement.

Oil and natural gas exploration and production activities – continued

										$ million
										2021
	Europe		**North America**		**South America**	**Africa**	**Asia**		**Australasia**	**Total**
	UK	**Rest of Europe**	**US**	**Rest of North America**			**Russia[a]**	**Rest of Asia**		
Equity-accounted entities (bp share)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	—	2,507	—	—	11,287	—	24,172	—	—	37,966
Unproved properties	—	383	—	—	98	—	4,362	—	—	4,843
	—	2,890	—	—	11,385	—	28,534	—	—	42,809
Accumulated depreciation	—	1,267	—	—	5,894	—	7,389	—	—	14,550
Net capitalized costs	—	1,623	—	—	5,491	—	21,145	—	—	28,259
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	—	—	—	—
Unproved	—	—	—	—	—	—	75	—	—	75
	—	—	—	—	—	—	75	—	—	75
Exploration and appraisal costs[d]	—	60	—	—	8	—	196	—	—	264
Development	—	430	—	—	539	—	2,677	—	—	3,646
Total costs	—	490	—	—	547	—	2,948	—	—	3,985
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	—	1,677	—	—	1,637	—	—	—	—	3,314
Sales between businesses	—	—	—	—	—	—	17,120	—	—	17,120
	—	1,677	—	—	1,637	—	17,120	—	—	20,434
Exploration expenditure	—	105	—	—	3	—	50	—	—	158
Production costs	—	222	—	—	487	—	1,335	—	—	2,044
Production taxes	—	—	—	—	308	—	9,291	—	—	9,599
Other costs (income)	—	26	—	—	34	—	293	—	—	353
Depreciation, depletion and amortization	—	347	—	—	404	—	1,633	—	—	2,384
Net impairments and losses on sale of businesses and fixed assets	—	108	—	—	(32)	—	191	—	—	267
	—	808	—	—	1,204	—	12,793	—	—	14,805
Profit (loss) before taxation	—	869	—	—	433	—	4,327	—	—	5,629
Allocable taxes	—	599	—	—	684	—	852	—	—	2,135
Results of operations	—	270	—	—	(251)	—	3,475	—	—	3,494

[a] Amounts reported for Russia in this table include bp's share of Rosneft's worldwide activities, including insignificant amounts outside Russia. See Note 37 Events after the reporting period.

[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.

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	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)

[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 and 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.

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

[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.

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	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)

[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.

Oil and natural gas exploration and production activities – continued

$ million

2019

	Europe UK	Europe Rest of Europe	North America US	North America Rest of North America	South America	Africa	Asia Russia[a]	Asia Rest of Asia	Australasia	Total
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

[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.

Movements in estimated net proved reserves

million barrels

Crude oil[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
2021	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	—	(46)	(32)	(3)	32	—	(121)	(1)	(171)
Improved recovery	—	—	29	—	—	2	—	—	—	32
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	2	—	—	—	—	5	—	7
Production	(30)	—	(113)	(9)	(2)	(41)	—	(116)	(5)	(315)
Sales of reserves-in-place	(1)	—	(5)				—	(36)	—	(41)
	(30)	—	(132)	(41)	(5)	(7)	—	(268)	(6)	(489)
At 31 December[c]										
Developed	178	—	705	24	5	117	—	930	28	1,987
Undeveloped	101	—	601	167	7	14	—	449	4	1,343
	279	—	1,306	191	12	131	—	1,379	33	3,330
Equity-accounted entities (bp share)[d]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	9	—	(5)	(4)	1	166	1	—	168
Improved recovery	—	1	—	—	—	—	—	—	—	1
Purchases of reserves-in-place	—	—	—	—	13	—	—	—	—	13
Discoveries and extensions	—	1	—	2	25	—	238	—	—	266
Production	—	(18)	—	(1)	(19)	—	(323)	—	—	(361)
Sales of reserves-in-place	—	(9)	—	—	—	—	(111)	—	—	(119)
	—	(15)	—	(4)	15	—	(30)	1	—	(33)
At 31 December[e f]										
Developed	—	100	—	10	275	3	3,045	1	—	3,434
Undeveloped	—	21	—	12	253	—	2,540	1	—	2,826
	—	121	—	22	527	3	5,585	1	—	6,260
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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
At 31 December										
Developed	178	100	705	34	280	119	3,045	931	28	5,421
Undeveloped	101	21	601	179	259	14	2,540	450	4	4,169
	279	121	1,306	213	539	134	5,585	1,381	33	9,590

[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 4 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[e] Includes 393 million barrels of crude oil in respect of the 7.16% non-controlling interest in Rosneft, including 22 mmbbl held through bp's interests in Russia other than Rosneft.

[f] Total proved crude oil reserves held as part of our equity interest in Rosneft is 5,490 million barrels, comprising 1 million barrels in Iraq and less than 1 million barrels each in Egypt, Vietnam, and Canada, and 5,487 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas liquids[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
										million barrels 2021
Subsidiaries										
At 1 January										
Developed	7	—	115	—	2	13	—	—	2	139
Undeveloped	—	—	218	—	19	1	—	—	—	237
	7	—	333	—	21	14	—	—	2	376
Changes attributable to										
Revisions of previous estimates	5	—	(1)	—	1	(1)	—	—	—	4
Improved recovery	—	—	25	—	—	—	—	—	—	25
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production[c]	(2)	—	(25)	—	(1)	(3)	—	—	(1)	(32)
Sales of reserves-in-place	(1)	—	(4)	—	—	—	—	—	—	(5)
	2	—	(5)	—	—	(4)	—	—	—	(8)
At 31 December[d]										
Developed	8	—	132	—	2	9	—	—	2	153
Undeveloped	—	—	195	—	19	1	—	—	—	215
	9	—	328	—	21	10	—	—	2	368
Equity-accounted entities (bp share)[e]										
At 1 January										
Developed	—	6	—	—	2	12	108	—	—	129
Undeveloped	—	1	—	—	—	—	43	—	—	44
	—	7	—	—	2	12	151	—	—	172
Changes attributable to										
Revisions of previous estimates	—	—	—	—	—	6	(9)	—	—	(2)
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(1)	(1)	—	—	(4)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	(1)	—	—	—	5	(10)	—	—	(7)
At 31 December[f g]										
Developed	—	6	—	—	2	17	100	—	—	125
Undeveloped	—	—	—	—	—	—	41	—	—	41
	—	6	—	—	2	17	140	—	—	166
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	7	6	115	—	4	25	108	—	2	268
Undeveloped	—	1	218	—	19	1	43	—	—	281
	7	7	333	—	23	26	151	—	2	549
At 31 December										
Developed	8	6	132	—	4	26	100	—	2	278
Undeveloped	—	—	195	—	19	1	41	—	—	256
	9	6	328	—	22	27	140	—	2	534

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

[d] Includes 6 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 3 million barrels of NGLs in respect of the 2.3% non-controlling interest in Rosneft.

[g] Total proved NGL reserves held as part of our equity interest in Rosneft is 140 million barrels, comprising less than 1 million barrels in Canada and 140 million barrels in Russia.

Movements in estimated net proved reserves – continued

million barrels

Total liquids[a b]										2021
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	168	—	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
Changes attributable to										
Revisions of previous estimates	5	—	(47)	(32)	(2)	31	—	(121)	(1)	(167)
Improved recovery	—	—	54	—	—	2	—	—	—	57
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	2	—	—	—	—	5	—	7
Production[c]	(32)	—	(138)	(9)	(3)	(44)	—	(116)	(5)	(348)
Sales of reserves-in-place	(1)	—	(9)	—	—	—	—	(36)	—	(46)
	(29)	—	(137)	(41)	(5)	(11)	—	(268)	(6)	(497)
At 31 December[d]										
Developed	187	—	837	24	7	125	—	930	30	2,141
Undeveloped	101	—	796	167	25	15	—	449	4	1,558
	288	—	1,634	191	32	140	—	1,379	34	3,699
Equity-accounted entities (bp share)[e]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	10	—	(5)	(4)	7	157	1	—	166
Improved recovery	—	1	—	—	—	—	—	—	—	1
Purchases of reserves-in-place	—	—	—	—	13	—	—	—	—	13
Discoveries and extensions	—	1	—	2	25	—	238	—	—	266
Production	—	(19)	—	(1)	(19)	(1)	(325)	—	—	(365)
Sales of reserves-in-place	—	(9)	—	—	—	—	(111)	—	—	(120)
	—	(16)	—	(4)	15	5	(40)	1	—	(39)
At 31 December[f g]										
Developed	—	106	—	10	276	20	3,145	1	—	3,558
Undeveloped	—	21	—	12	253	—	2,581	1	—	2,867
	—	127	—	22	529	20	5,726	1	—	6,425
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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
At 31 December										
Developed	187	106	837	34	284	146	3,145	931	30	5,699
Undeveloped	101	21	796	179	278	15	2,581	450	4	4,425
	288	127	1,634	213	561	161	5,726	1,381	34	10,124

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

[d] Also includes 10 million barrels 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 396 million barrels of liquids in respect of the non-controlling interest in Rosneft, including 22 mmboe held through bp's interests in Russia other than Rosneft.

[g] Total proved liquid reserves held as part of our equity interest in Rosneft is 5,630 million barrels, comprising 1 million barrels in Iraq, less than 1 million barrels each in Canada, Egypt and Vietnam and 5,628 million barrels in Russia.

Movements in estimated net proved reserves – continued

										billion cubic feet
Natural gas[a b]										**2021**
	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	**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**
Changes attributable to										
Revisions of previous estimates	**254**	**—**	**717**	**1**	**(767)**	**537**	**—**	**(66)**	**(285)**	**390**
Improved recovery	**—**	**—**	**247**	**—**	**—**	**—**	**—**	**—**	**—**	**247**
Purchases of reserves-in-place	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Discoveries and extensions	**—**	**—**	**1**	**—**	**—**	**25**	**—**	**116**	**—**	**142**
Production[c]	**(103)**	**—**	**(445)**	**(1)**	**(465)**	**(516)**	**—**	**(489)**	**(279)**	**(2,297)**
Sales of reserves-in-place	**(7)**	**—**	**(60)**	**—**	**—**	**—**	**—**	**(1,298)**	**—**	**(1,365)**
	143	**—**	**461**	**—**	**(1,232)**	**46**	**—**	**(1,736)**	**(564)**	**(2,883)**
At 31 December[d]										
Developed	**455**	**—**	**2,401**	**—**	**1,152**	**1,433**	**—**	**3,266**	**1,584**	**10,291**
Undeveloped	**45**	**—**	**3,404**	**—**	**1,147**	**154**	**—**	**2,522**	**939**	**8,211**
	501	**—**	**5,805**	**—**	**2,299**	**1,587**	**—**	**5,788**	**2,523**	**18,502**
Equity-accounted entities (bp share)[e]										
At 1 January										
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**
Changes attributable to										
Revisions of previous estimates	**—**	**8**	**—**	**(2)**	**(115)**	**152**	**422**	**—**	**—**	**467**
Improved recovery	**—**	**4**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**4**
Purchases of reserves-in-place	**—**	**—**	**—**	**—**	**3**	**—**	**—**	**—**	**—**	**3**
Discoveries and extensions	**—**	**1**	**—**	**1**	**222**	**—**	**151**	**—**	**—**	**375**
Production[c]	**—**	**(25)**	**—**	**—**	**(124)**	**(72)**	**(478)**	**(3)**	**—**	**(702)**
Sales of reserves-in-place	**—**	**(9)**	**—**	**—**	**—**	**—**	**(102)**	**(4)**	**—**	**(115)**
	—	**(22)**	**—**	**(1)**	**(13)**	**80**	**(7)**	**(7)**	**—**	**31**
At 31 December[f g]										
Developed	**—**	**130**	**—**	**4**	**929**	**689**	**11,399**	**—**	**—**	**13,149**
Undeveloped	**—**	**11**	**—**	**4**	**536**	**133**	**7,279**	**—**	**—**	**7,964**
	—	**140**	**—**	**8**	**1,465**	**822**	**18,678**	**—**	**—**	**21,113**
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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**
At 31 December										
Developed	**455**	**130**	**2,401**	**4**	**2,081**	**2,121**	**11,399**	**3,266**	**1,584**	**23,440**
Undeveloped	**45**	**11**	**3,404**	**4**	**1,683**	**287**	**7,279**	**2,522**	**939**	**16,174**
	501	**140**	**5,805**	**8**	**3,764**	**2,408**	**18,678**	**5,788**	**2,523**	**39,615**

[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 135 billion cubic feet of natural gas consumed in operations, 83 billion cubic feet in subsidiaries, 52 billion cubic feet in equity-accounted entities.

[d] Includes 690 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 1,656 billion cubic feet of natural gas in respect of the 10.20% non-controlling interest in Rosneft including 621 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 16,233 billion cubic feet, comprising less than 1billion cubic feet in Vietnam and Canada, 376 billion cubic feet in Egypt and 15,857 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]										2021
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[f]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	49	—	77	(32)	(134)	123	—	(132)	(50)	(100)
Improved recovery	—	—	97	—	—	2	—	—	—	99
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	2	—	—	4	—	25	—	31
Production[d e]	(50)	—	(214)	(9)	(83)	(133)	—	(200)	(54)	(744)
Sales of reserves-in-place	(3)	—	(19)	—	—	—	—	(260)	—	(282)
	(4)	—	(58)	(41)	(217)	(3)	—	(567)	(104)	(994)
At 31 December[f]										
Developed	265	—	1,251	24	206	372	—	1,494	303	3,915
Undeveloped	109	—	1,383	167	223	41	—	884	166	2,973
	374	—	2,634	191	429	414	—	2,377	469	6,889
Equity-accounted entities (bp share)[g]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	11	—	(5)	(24)	33	230	1	—	246
Improved recovery	—	1	—	—	—	—	—	—	—	1
Purchases of reserves-in-place	—	—	—	—	14	—	—	—	—	14
Discoveries and extensions	—	1	—	2	63	—	264	—	—	330
Production[e]	—	(23)	—	(1)	(41)	(14)	(407)	—	—	(486)
Sales of reserves-in-place	—	(11)	—	—	—	—	(128)	(1)	—	(139)
	—	(20)	—	(4)	12	19	(42)	—	—	(34)
At 31 December[h i]										
Developed	—	128	—	11	437	139	5,110	1	—	5,825
Undeveloped	—	23	—	12	345	23	3,836	1	—	4,240
	—	151	—	23	782	162	8,946	1	—	10,065
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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
At 31 December										
Developed	265	128	1,251	35	642	511	5,110	1,494	303	9,740
Undeveloped	109	23	1,383	179	568	65	3,836	884	166	7,214
	374	151	2,634	214	1,210	576	8,946	2,379	469	16,954

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

[e] Includes 23 million barrels of oil equivalent of natural gas consumed in operations, 14 million barrels of oil equivalent in subsidiaries, 9 million barrels of oil equivalent in equity-accounted entities.

[f] Includes 130 million barrels of oil equivalent 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 682 million barrels of oil equivalent in respect of the 8.09% non-controlling interest in Rosneft, including 129mmboe held through bp's interests in Russia other than Rosneft.

[i] Total proved reserves held as part of our equity interest in Rosneft is 8,429 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada and Vietnam, 1million barrels of oil equivalent in Iraq, 65 million barrels of oil equivalent in Egypt and 8,362 million barrels of oil equivalent in Russia.

Movements in estimated net proved reserves – continued

Crude oil[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia[c]		million barrels 2020
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

Natural gas liquids[a b]										million barrels 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[d]	—	(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

Total liquids[a b]										million barrels 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	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[d]	—	(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 19 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 5,683 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

Natural gas[a b]										billion cubic feet 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 1,316 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

Total hydrocarbons[a b]										million barrels of oil equivalent[c] 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[g]										
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 124 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 8,498 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

										billion cubic feet
Natural gas[a b]										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.

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
										2021
	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]	25,600	—	108,600	8,400	10,300	17,100	—	126,800	20,400	317,200
Future production cost[b]	13,400	—	33,900	3,700	4,300	4,800	—	46,100	6,400	112,600
Future development cost[b]	1,100	—	12,600	1,100	1,300	1,100	—	12,400	2,100	31,700
Future taxation[c]	4,300	—	10,100	500	1,400	2,900	—	44,100	4,100	67,400
Future net cash flows	6,800	—	52,000	3,100	3,300	8,300	—	24,200	7,800	105,500
10% annual discount[d]	2,100	—	21,600	1,700	600	1,400	—	8,300	2,900	38,600
Standardized measure of discounted future net cash flows[e]	4,700	—	30,400	1,400	2,700	6,900	—	15,900	4,900	66,900
Equity-accounted entities (bp share)[f]										
Future cash inflows[a]	—	10,500	—	—	40,100	—	370,000	—	—	420,600
Future production cost[b]	—	3,400	—	—	16,600	—	254,000	—	—	274,000
Future development cost[b]	—	400	—	—	3,900	—	24,300	—	—	28,600
Future taxation[c]	—	5,100	—	—	6,100	—	15,600	—	—	26,800
Future net cash flows	—	1,600	—	—	13,500	—	76,100	—	—	91,200
10% annual discount[d]	—	400	—	—	7,800	—	45,200	—	—	53,400
Standardized measure of discounted future net cash flows[g h]	—	1,200	—	—	5,700	—	30,900	—	—	37,800
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[i]	4,700	1,200	30,400	1,400	8,400	6,900	30,900	15,900	4,900	104,700

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

			$ million
	Subsidiaries	Equity-accounted entities (bp share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(12,200)	(7,700)	(19,900)
Development costs for the current year as estimated in previous year	5,800	3,600	9,400
Extensions, discoveries and improved recovery, less related costs	1,700	2,400	4,100
Net changes in prices and production cost	71,900	29,700	101,600
Revisions of previous reserves estimates	(8,800)	1,000	(7,800)
Net change in taxation	(17,900)	(7,200)	(25,100)
Future development costs	(3,200)	(5,300)	(8,500)
Net change in purchase and sales of reserves-in-place	(3,100)	(600)	(3,700)
Addition of 10% annual discount	3,000	2,000	5,000
Total change in the standardized measure during the year[j]	37,200	17,900	55,100

[a] The marker prices used were Brent $69.23/bbl, Henry Hub $3.61/mmBtu.

[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.

[c] Taxation is computed with reference to appropriate year-end statutory corporate income tax rates.

[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.

[e] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $820 million.

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

[g] Non-controlling interests in Rosneft amounted to $2,422 million in Russia. See Note 37 Events after the reporting period.

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

[i] Includes future net cash flows for assets held for sale at 31 December 2021.

j Total change in the standardized measure during the year includes the effect of exchange rate movements. Exchange rate effects arising from the translation of our share of Rosneft changes to US dollars are included within 'Net changes in prices and production cost'.

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

$ million

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'.

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 2021, 2020 and 2019.

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
2021	**82**	**—**	**308**	**25**	**5**	**110**	**—**	**318**	**13**	**860**
2020	96	—	345	22	7	123	—	375	15	983
2019	100	—	400	24	7	156	—	343	17	1,046
Natural gas liquids										thousand barrels per day
2021	**5**	**—**	**70**	**—**	**4**	**7**	**—**	**—**	**2**	**88**
2020	5	—	79	—	7	8	—	—	2	101
2019	3	—	81	—	9	8	—	—	2	104
Natural gas[f]										million cubic feet per day
2021	**236**	**—**	**1,197**	**2**	**1,260**	**1,332**	**—**	**1,279**	**760**	**6,067**
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
Equity-accounted entities (bp share)										
Crude oil[e]										thousand barrels per day
2021	**—**	**48**	**—**	**—**	**55**	**1**	**887**	**—**	**—**	**991**
2020	—	50	—	—	54	1	903	—	—	1,009
2019	—	35	—	—	56	1	955	—	—	1,047
Natural gas liquids										thousand barrels per day
2021	**—**	**3**	**—**	**—**	**1**	**6**	**3**	**—**	**—**	**12**
2020	—	3	—	—	1	7	3	—	—	14
2019	—	2	—	—	1	8	3	—	—	14
Natural gas[f]										million cubic feet per day
2021	**—**	**66**	**—**	**—**	**284**	**77**	**1,423**	**—**	**—**	**1,849**
2020	—	61	—	—	286	92	1,327	—	—	1,765
2019	—	56	—	—	314	87	1,279	—	—	1,736

[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.

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 2021. 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 2021											
Oil wells[c]	– gross	**106**	**92**	**1,441**	**178**	**5,125**	**297**	**58,704**	**2,275**	**12**	**68,230**
	– net	**59**	**26**	**791**	**50**	**2,526**	**63**	**13,030**	**506**	**2**	**17,053**
Gas wells[d]	– gross	**35**	**3**	**4,305**	**237**	**1,135**	**233**	**435**	**149**	**86**	**6,618**
	– net	**6**	**1**	**2,365**	**117**	**413**	**97**	**99**	**54**	**17**	**3,171**
Oil and natural gas acreage at 31 December 2021											thousands of acres
Developed	– gross	**68**	**64**	**3,167**	**147**	**1,293**	**1,025**	**7,605**	**1,313**	**181**	**14,863**
	– net	**38**	**18**	**1,869**	**64**	**360**	**379**	**1,489**	**269**	**44**	**4,529**
Undeveloped[e]	– gross	**2,154**	**140**	**4,241**	**15,595**	**21,565**	**30,997**	**436,104**	**10,306**	**7,491**	**528,592**
	– net	**1,171**	**39**	**3,248**	**8,539**	**7,833**	**17,839**	**91,408**	**2,543**	**3,234**	**135,854**

[a] Based on information received from Rosneft as at 31 December 2021.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Includes approximately 5821 gross (1261 net) multiple completion wells (more than one formation producing into the same well bore).
[d] Includes approximately 161 gross (135 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		
2021										
Exploratory										
Productive	**—**	**—**	**0.2**	**—**	**1.1**	**1.4**	**16.3**	**1.2**	**—**	**20.2**
Dry	**—**	**—**	**0.6**	**—**	**—**	**1.4**	**—**	**0.3**	**0.4**	**2.7**
Development										
Productive	**2.4**	**0.6**	**107.2**	**0.8**	**69.4**	**2.5**	**285.2**	**27.3**	**1.3**	**496.6**
Dry	**—**	**0.1**	**7.3**	**—**	**0.7**	**—**	**—**	**0.1**	**—**	**8.2**
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

[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 2021. 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 2021										
Exploratory										
Gross	—	—	3.0	1.0	—	—	—	6.0	—	10.0
Net	—	—	2.3	0.4	—	—	—	0.9	—	3.6
Development										
Gross	3.0	3.5	181.0	6.0	21.0	15.0	—	160.0	3.0	392.5
Net	1.5	1.0	106.7	3.0	5.6	3.6	—	22.8	1.0	145.0

[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 income statement

For the year ended 31 December			$ million
	Note	**2021**	2020
Dividend income		**851**	2,008
Interest and other income		**405**	688
Total income		**1,256**	2,696
Administrative and other expenses		**7**	(452)
Impairment of fixed asset investments	2	**(1,109)**	(5,967)
Gain on sale of businesses and fixed assets		**—**	5
Profit (loss) before interest and taxation		**154**	(3,718)
Interest payable to subsidiaries		**(531)**	(1,198)
Net finance income (expense) relating to pensions	4	**126**	129
Profit (loss) before taxation		**(251)**	(4,787)
Taxation	6	**(142)**	(44)
Profit (loss) for the year		**(393)**	(4,831)

Company statement of comprehensive income

For the year ended 31 December			$ million
	Note	**2021**	2020
Profit (loss) for the year		**(393)**	(4,831)
Other comprehensive income			
Items that may be reclassified subsequently to profit or loss			
Currency translation differences		**(111)**	280
		(111)	280
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension liability or asset	4	**2,410**	542
Income tax relating to items that will not be reclassified	6	**(802)**	(294)
		1,608	248
Other comprehensive income		**1,497**	528
Total comprehensive income		**1,104**	(4,303)

The parent company financial statements of BP p.l.c. on pages 282-336 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Company balance sheet

At 31 December			$ million
	Note	**2021**	2020
Non-current assets			
Investments	2	**159,662**	160,544
Receivables	3	**3,234**	3,174
Defined benefit pension plan surpluses	4	**10,281**	7,567
		173,177	171,285
Current assets			
Receivables	3	**320**	291
Cash and cash equivalents		**27**	1
		347	292
Total assets		**173,524**	171,577
Current liabilities			
Payables	5	**9,176**	28,011
Non-current liabilities			
Payables	5	**53,658**	28,084
Deferred tax liabilities	6	**3,575**	2,631
Defined benefit pension plan deficits	4	**237**	236
		57,470	30,951
Total liabilities		**66,646**	58,962
Net assets		**106,878**	112,615
Capital and reserves[a]			
Profit and loss account			
Brought forward		**79,721**	92,071
Profit (loss) for the year		**(393)**	(4,831)
Other movements		**(6,004)**	(7,519)
		73,324	79,721
Called-up share capital	7	**5,215**	5,383
Share premium account		**12,745**	12,584
Other capital and reserves		**15,594**	14,927
		106,878	112,615

[a] See Statement of changes in equity on page 284 for further information.

The financial statements on pages 282-336 were approved and signed by the chief executive officer on 18 March 2022 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 282-336 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 2021	**5,383**	**12,584**	**1,528**	**26,509**	**(13,224)**	**114**	**79,721**	**112,615**
Profit (loss) for the year	**—**	**—**	**—**	**—**	**—**	**—**	**(393)**	**(393)**
Other comprehensive income	**—**	**—**	**—**	**—**	**—**	**(111)**	**1,608**	**1,497**
Total comprehensive income	**—**	**—**	**—**	**—**	**—**	**(111)**	**1,215**	**1,104**
Dividends	**—**	**—**	**—**	**—**	**—**	**—**	**(4,316)**	**(4,316)**
Repurchases of ordinary share capital[b]	**(177)**	**—**	**177**	**—**	**—**	**—**	**(3,151)**	**(3,151)**
Share-based payments, net of tax	**9**	**161**	**—**	**—**	**601**	**—**	**(145)**	**626**
At 31 December 2021	**5,215**	**12,745**	**1,705**	**26,509**	**(12,623)**	**3**	**73,324**	**106,878**
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

[a] See Note 8 for further information.

[b] See Note 7 for further information.

The parent company financial statements of BP p.l.c. on pages 282-336 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 2021 were approved and signed by the chief executive officer on 18 March 2022 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 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';

(b) 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.

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

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

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

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

(g) the 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;

(h) the requirements of paragraphs 45(b) and 46 to 52 of IFRS 2 'Share-based Payment';

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

(l) 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.

The income statement of the company for 2021 with comparatives is presented for the first time this year.

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

Significant accounting policies: use of judgements, estimates and assumptions

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for 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 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. This, in turn, may affect the recoverable amount of a parent's investments in subsidiaries. Management's best estimate oil and natural gas price assumptions for value-in-use impairment testing were revised during 2021. The assumption up to 2030 was increased to reflect near-term supply constraints whereas the long-term assumption was decreased as bp's management expects an acceleration of the pace of transition to a lower carbon economy. Henry Hub gas price assumptions remain unchanged from 2020 except that the assumption for 2022 has been increased to reflect short term market conditions. The revised assumptions sit within the range of external scenarios considered by management and are in line with a range of transition paths consistent with the temperature goal of the Paris climate change agreement 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.

The parent company financial statements of BP p.l.c. on pages 282-336 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 145 to 253) continue to be prepared on a going concern basis. 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. 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 2021 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 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, carbon pricing (where applicable), 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. Determination as to whether, and by how much, an asset or CGU is impaired involves similar estimates.

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 2021 relating to discount rates and oil and gas properties are discussed below. It is impracticable to reliably determine the extent of any impacts of changes in the assumptions used to determine the recoverable amounts of the company's investments given the diverse characteristics of the underlying assets and the interdependency of the various inputs. Changes in the economic environment including as a result of the energy transition 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 a post-tax discount rate. The discount rates applied in impairment tests are reassessed each year and in 2021 the pre-tax discount rate typically ranged from 7% to 15% (2020 7% to 15%) 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 and certain resources 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.

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

Oil and natural gas prices

The price assumptions used for value in use impairment testing are based on those used for investment appraisal. bp's carbon emissions cost assumptions and their interrelationship with oil and gas prices are described in 'Judgements and estimates made in assessing the impact of climate change and the transition to a lower carbon economy' on page 178. The investment appraisal price assumptions are recommended by the senior vice president economic & energy insights after considering a range of external price sets and supply and demand profiles associated with 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 scenarios considered include those where those goals are met as well as those where they are not met.

During the year, bp's price assumptions applied in value in use impairment testing for Brent oil up to 2030 were increased to reflect near-term supply constraints. bp's management also expects an acceleration of the pace of transition to a lower carbon economy. As such, the long-term Brent oil assumptions were decreased during the year, reaching $55 per barrel by 2040 and $45 per barrel by 2050 (in 2020 real terms). The price assumptions applied in value in use impairment testing for Henry Hub gas were unchanged to those used in 2020 except that the assumption for 2022 was increased to reflect short term market conditions. These price assumptions are derived from the central case investment appraisal assumptions, adjusted where applicable to reflect short-term market conditions (see page 32). A summary of the group's revised price assumptions, for Brent oil and Henry Hub gas, applied in 2021 and 2020, in real 2020 terms, is provided below. The assumptions represent management's best estimate of future prices at the balance sheet date, which sit within the range of external scenarios considered as appropriate for the purpose. They are considered by bp to be in line with a range of transition paths consistent with the temperature goal of the Paris climate change agreement, of holding 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. However, they do not correspond to any specific Paris-consistent scenario. An inflation rate of 2% (2020 2%) is applied to determine the price assumptions in nominal terms.

2021 price assumptions	**2022**	**2025**	**2030**	**2040**	**2050**
Brent oil ($/bbl)	70	60	60	55	45
Henry Hub gas ($/mmBtu)	4.00	3.00	3.00	3.00	2.75

2020 price assumptions	**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

The majority of bp's reserves and resources that support the carrying value of the company's subsidiaries holding upstream 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.

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

Share-based payments

Equity-settled transactions

The cost of equity-settled transactions with employees of the company and other members of the group is measured by reference to the fair value of the equity instruments on the date on which they are granted. The cost relating to employees of the company is recognized as an expense and the cost relating to other members of the group is recognized as a cost of investment in subsidiaries 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 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

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 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.

The parent company financial statements of BP p.l.c. on pages 282-336 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

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

Deferred tax assets 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.

Impact of new International Financial Reporting Standards

The company adopted 'Interest Rate Benchmark Reform – Phase II – Amendments to IFRS 9 'Financial instruments', IFRS 16 'Leases' and other IFRSs' with effect from 1 January 2021 and it was was applied prospectively from that date. There are no other new or amended standards or interpretations adopted during the year that have a significant impact on the financial statements.

Voluntary change in accounting policy – Cost of equity-settled transactions with employees of other members of the group are recognised as a cost of investment in subsidiaries

As of 1 January 2021, the company recognises the cost of equity-settled transactions with employees of other members of the group as a cost of investment in subsidiaries. The company previously recognised the cost of equity-settled transactions with employees of other members of the group as an expense.

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2. Investments

			$ million
	Subsidiaries[a]	Associates	
	Shares	Shares	Total
Cost			
At 1 January 2021	**166,540**	**2**	**166,542**
Additions	**220**	**7**	**227**
At 31 December 2021	**166,760**	**9**	**166,769**
Amounts provided			
At 1 January 2021	**5,998**	**—**	**5,998**
Additions	**1,109**	**—**	**1,109**
At 31 December 2021	**7,107**	**—**	**7,107**
Cost			
At 1 January 2020	166,287	2	166,289
Additions	255	—	255
Disposals	(2)	—	(2)
At 31 December 2020	166,540	2	166,542
Amounts provided			
At 1 January 2020	33	—	33
Additions	5,965	—	5,965
At 31 December 2020	5,998	—	5,998
At 31 December 2021	**159,653**	**9**	**159,662**
At 31 December 2020	160,542	2	160,544

At 31 December 2021, the carrying amount of the company's net assets of $106.9 billion (2020 $112.6 billion) exceeded the group's market capitalisation of $88.1 billion (2020 $70.5 billion). As a result, management performed an impairment test of the company's major investments in line with the requirements of IAS 36 Impairment of Assets. In 2020, an impairment charge of $5,965 million[a] was recognized following the performance of an impairment review in line with the requirements of IAS 36. In 2021, management performed a subsequent review of the company's major investments to identify indicators of potential further impairment. Taking into account the increase in the group's market capitalisation, a decrease in the deficits between the carrying amount of the company's major investments compared with the underlying net assets and the upward revision of oil and natural gas prices, compared to 2020, management concluded that there were no further impairments in terms of a deterioration of value in use or fair value less costs to sell except for anticipated portfolio changes within an operating subsidiary which has resulted in an impairment charge of $1,109 million. Notwithstanding that there have been certain impairment reversals within some of the group's operating subsidiaries during the year, no reversals of previously recognized impairment provisions were determined to be required in respect of the company's investments in subsidiaries.

See also note 13. Events after the reporting period

[a] 2020 amounts have been restated as a result of a voluntary change in accounting policy. See note 1 - Voluntary change in accounting policy – Cost of equity-settled transactions with employees of other members of the group are recognised as a cost of investment in subsidiaries

The more important subsidiaries of the company at 31 December 2021 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 Limited	100	England & Wales	Investment holding
BP International Limited	100	England & Wales	Integrated oil operations
Burmah Castrol PLC	100	Scotland	Lubricants
Canada			
BP Holdings Canada Limited	100	England & Wales	Investment holding
US			
BP Holdings North America Limited	100	England & Wales	Investment holding

The carrying value of the investment in BP International Limited at 31 December 2021 was $75,633 million (2020 $75,645 million).

3. Receivables

				$ million
		2021		2020
	Current	Non-current	Current	Non-current
Amounts receivable from subsidiaries[a]	**311**	**3,234**	284	3,174
Amounts receivable from associates	**6**	**—**	7	—
Other receivables	**3**	**—**	—	—
	320	**3,234**	291	3,174

[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.

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4. Pensions

The pension obligation consists primarily of 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 was closed to new joiners in 2010 and was closed to future accrual on 30 June 2021 resulting in a curtailment gain of $0.3 billion being recognized in the income statement during the year. For active members of the plan at 30 June 2021, benefits payable are now linked to salary as at that date, rather than salary on retirement. Employees in the UK are eligible for membership of a defined contribution plan.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2021 the aggregate level of contributions was $134 million (2020 $189 million). No contributions are expected in 2022.

For the primary UK plan there is a funding agreement between the company and the trustee. On a three year cycle a schedule of contributions is agreed covering the next five years. The schedule of contributions is next scheduled to be updated after the 31 December 2023 formal actuarial valuation. No contractually committed funding was due at 31 December 2021. The closure of the defined benefit plan to future accrual and the consequent lower service cost reduces the plan's expected future funding volatility.

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 2021. 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 2020.

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 [a]		%
	2021	2020
Discount rate for pension plan liabilities	**1.8**	1.4
Rate of increase for pensions in payment	**3.2**	2.8
Rate of increase in deferred pensions	**3.2**	2.8
Inflation for pension plan liabilities	**3.3**	2.9

Financial assumptions used to determine benefit expense		%
	2021	2020
Discount rate for pension plan service costs	**1.5**	2.1
Discount rate for pension plan other finance expense [b]	**1.7**	2.1
Inflation for pension plan service costs	**2.8**	2.6

[a] Salary growth is no longer a material financial assumption for the UK following the closure of the primary pension plan to future accrual. The rate of increase in salaries for the UK was 3.6% in 2020.

[b] The discount rate for plan other finance expense was 1.4% for the primary UK plan for the period before the plan closed to future accrual on 30th June 2021 and 1.9% thereafter.

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.

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
	2021	2020
Life expectancy at age 60 for a male currently aged 60	**26.9**	26.9
Life expectancy at age 60 for a male currently aged 40	**28.4**	28.4
Life expectancy at age 60 for a female currently aged 60	**28.9**	28.8
Life expectancy at age 60 for a female currently aged 40	**30.5**	30.4

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.

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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. This agreement is not impacted by the closure of the plan to future accrual. During 2021, the plan switched 5% from equities to bonds (2020 11%).

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

Asset category	%
Total equity (including private equity)	12
Bonds/cash (including LDI)	81
Property/real estate	7

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2021 were $7,399 million (2020 $4,217 million) of government-issued nominal bonds and $24,516 million (2020 $24,576 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 293.

		$ million
	2021	2020
Fair value of pension plan assets		
Listed equities – developed markets	2,964	5,008
– emerging markets	252	418
Private equity[a]	3,233	2,899
Government issued nominal bonds[b]	7,491	4,303
Government issued index-linked bonds[b]	24,516	24,576
Corporate bonds[b]	10,128	8,906
Property[c]	2,714	2,553
Cash	1,136	1,392
Other	1,133	795
Debt (repurchase agreements) used to fund liability driven investments	(10,723)	(9,387)
	42,844	41,463

[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 professional valuers that generally result in the use of significant unobservable inputs.

		$ million
	2021	2020
Analysis of the amount charged to profit or loss		
Current service cost[a]	154	250
Past service income[b]	(302)	(48)
Operating charge / (credit) relating to defined benefit plans	(148)	202
Payments to defined contribution plan	76	49
Total operating charge / (credit)	(72)	251
Interest income on plan assets[c]	(684)	(724)
Interest on plan liabilities	558	595
Other finance (income)	(126)	(129)
Analysis of the amount recognized in other comprehensive income		
Actual asset return less interest income on pension plan assets	2,440	4,108
Change in financial assumptions underlying the present value of the plan liabilities	(103)	(4,205)
Change in demographic assumptions underlying the present value of plan liabilities	66	585
Experience gains and losses arising on the plan liabilities	7	54
Remeasurements recognized in other comprehensive income	2,410	542

[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 the closure of the primary pension plan in the UK to future accrual in 2021 and from restructuring programmes in 2020.

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

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4. Pensions – continued

	$ million 2021	2020
Movements in benefit obligation during the year		
Benefit obligation at 1 January	**34,132**	29,743
Exchange adjustments	**(254)**	1,302
Operating charge relating to defined benefit plans	**(148)**	202
Interest cost	**558**	595
Contributions by plan participants[a]	**18**	21
Benefit payments (funded plans)[b]	**(1,530)**	(1,291)
Benefit payments (unfunded plans)[b]	**(6)**	(6)
Remeasurements	**30**	3,566
Benefit obligation at 31 December	**32,800**	34,132
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	**41,463**	36,129
Exchange adjustments	**(365)**	1,583
Interest income on plan assets[c]	**684**	724
Contributions by plan participants[a]	**18**	21
Contributions by employers (funded plans)	**134**	189
Benefit payments (funded plans)[b]	**(1,530)**	(1,291)
Remeasurements[c]	**2,440**	4,108
Fair value of plan assets at 31 December[d e]	**42,844**	41,463
Surplus at 31 December	**10,044**	7,331
Represented by		
Asset recognized	**10,281**	7,567
Liability recognized	**(237)**	(236)
	10,044	7,331
The surplus may be analysed between funded and unfunded plans as follows		
Funded	**10,281**	7,564
Unfunded	**(237)**	(233)
	10,044	7,331
The defined benefit obligation may be analysed between funded and unfunded plans as follows		
Funded	**(32,563)**	(33,899)
Unfunded	**(237)**	(233)
	(32,800)	(34,132)

[a] Most of the contributions made by plan participants were made under salary sacrifice.
[b] The benefit payments amount shown above comprises $1,507 million benefits (2020 $1,280 million) plus $29 million (2020 $17 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 $42,459 million of assets held in the BP Pension Fund (2020 $41,088 million) and $319 million held in the BP Global Pension Trust (2020 $306 million), as well as $51 million representing the company's share of Merchant Navy Officers Pension Fund (2020 $53 million) and $15 million of Merchant Navy Ratings Pension Fund (2020 $16 million).
[e] The fair value of plan assets includes borrowings related to the LDI programme as described on page 292.

Sensitivity analysis

The discount rate, inflation 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 2021 for the company's plans would have had the effects shown in the table below. The effects shown for the expense in 2022 primarily comprise the impact on net finance income or expense, but include the impact on current service cost where relevant.

	$ million One percentage point Increase	Decrease
Discount rate[a]		
Effect on pension expense in 2022	**(248)**	**159**
Effect on pension obligation at 31 December 2021	**(5,139)**	**6,783**
Inflation rate[b]		
Effect on pension expense in 2022	**74**	**(71)**
Effect on pension obligation at 31 December 2021	**4,062**	**(3,912)**

[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 pensions in payment and deferred pensions.

One additional year of longevity in the mortality assumptions would increase the 2022 pension expense by $25 million and the pension obligation at 31 December 2021 by $1,400 million.

The parent company financial statements of BP p.l.c. on pages 282-336 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 2031 and the weighted average duration of the defined benefit obligations at 31 December 2021 are as follows:

	$ million
Estimated future benefit payments	
2022	**1,098**
2023	**1,140**
2024	**1,161**
2025	**1,162**
2026	**1,183**
2027-2031	**6,176**
	Years
Weighted average duration	**17.9**

5. Payables

				$ million
	2021			2020
	Current	**Non-current**	Current	Non-current
Amounts payable to subsidiaries	**9,084**	**53,606**	27,933	28,060
Accruals	**2**	**—**	2	—
Other payables	**90**	**52**	76	24
	9,176	**53,658**	28,011	28,084

Included in current amounts payable to subsidiaries is an interest-bearing payable of $5,032 million (2020 $5,033 million) with BP Finance p.l.c., 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 p.l.c. at one business day's notice. It is disclosed as a non-current receivable in the financial statements of BP Finance p.l.c., given the counterparty has no intent to call the loan at short notice.

The company also has current payables of $4,023 million on Internal Funding Accounts (IFAs) payable to BP International Limited. 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.

Non-current amounts payable to subsidiaries includes an interest-bearing payable of $52,585 million with BP International Limited issued in December 2021, with interest being charged based on a 3-month USD LIBOR rate plus 75 basis points and a maturity date of December 2028. This new $60,000 million long-term loan facility replaces term loans with BP International Limited of $4,236 million that matured in December 2021 and $27,100 million with a maturity date of May 2023, providing additional long-term funding to the company. The loan includes a prepayment clause for BP p.l.c. to repay part or all of the loan before maturity whilst the lender has no right to call the loan other than in the event of the company being in default. As such it is disclosed as non-current in both the company and BP International Limited financial statements.

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

		$ million
	2021	2020
Due within		
1 to 2 years	**40**	30
2 to 5 years	**179**	27,259
More than 5 years	**53,439**	795
	53,658	28,084

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6. Taxation

Tax charge included in total comprehensive income	2021	2020
		$ million
Deferred tax		
Origination and reversal of temporary differences in the current year	**944**	338
This comprises:		
Taxable temporary differences relating to pensions	**944**	338
Deferred tax		
Deferred tax liability		
Pensions	**3,575**	2,631
Net deferred tax liability	**3,575**	2,631
Analysis of movements during the year		
At 1 January	**2,631**	2,293
Charge (credit) for the year in the income statement	**142**	44
Charge (credit) for the year in other comprehensive income	**802**	294
At 31 December	**3,575**	2,631

At 31 December 2021, deferred tax assets of $709 million on other temporary differences comprising $16 million relating to pensions, $99 million relating to income losses and $594 million relating to other deductible temporary differences (2020 $375 million on other temporary differences comprising $12 million relating to pensions, $75 million relating to income losses and $288 million relating to other deductible temporary differences) 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:

	2021		2020	
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	**21,449,782**	**5,362**	21,535,840	5,383
Issue of new shares for the scrip dividend programme	**—**	**—**	—	—
Issue of new shares for employee share-based payment plans	**35,000**	**9**	34,000	9
Repurchase of ordinary share capital	**(706,701)**	**(177)**	(120,058)	(30)
At 31 December	**20,778,081**	**5,194**	21,449,782	5,362
		5,215		5,383

[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 2021 the company repurchased 707 million ordinary shares at a cost of $3,151 million, including transaction costs of $17 million, as part of the share repurchase programme announced on 27 April 2021. All shares purchased were for cancellation. The repurchased shares represented 3.4% of ordinary share capital.

7. Called-up share capital – continued

Treasury shares[a]

	2021		2020	
	Shares thousand	**Nominal value $ million**	Shares thousand	Nominal value $ million
At 1 January	**1,187,650**	**296**	1,296,856	323
Purchases for settlement of employee share plans	**1,432**	**—**	—	—
Issue of new shares for employee share-based payment plans	**35,096**	**9**	34,116	9
Shares re-issued for employee share-based payment plans	**(86,721)**	**(22)**	(143,322)	(36)
At 31 December	**1,137,457**	**283**	1,187,650	296
Of which - shares held in treasury by bp	**1,037,201**	**259**	1,105,157	275
- shares held in ESOP trusts	**100,256**	**24**	82,491	21
- shares held by bp's US plan administrator[b]	**—**	**—**	2	—

[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 5.2% (2020 5.4%) of the called-up ordinary share capital of the company.

During 2021, the movement in shares held in treasury by bp represented less than 0.3% (2020 less than 0.3%) 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 $24,107 million (2020 $23,600 million), the distribution of which is limited by statutory or other restrictions.

The financial statements for the year ended 31 December 2021 do not reflect the dividend announced on 8 February 2022 which will be paid in March 2022; this will be treated as an appropriation of profit in the year ended 31 December 2022.

9. Financial guarantees

The company has issued guarantees under which the maximum aggregate liabilities at 31 December 2021 were $69,611 million (2020 $80,891 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 32 in the consolidated group financial statements of BP p.l.c. for further information.

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10. Auditor's remuneration

Note 35 to the consolidated financial statements provides details of the remuneration of the company's auditor on a group basis.

11. Directors' remuneration

		$ million
Remuneration of directors	2021	2020
Total for all directors		
Emoluments	**9**	6
Amounts awarded under incentive schemes[a]	**4**	14
Total	**13**	20

[a] Excludes amounts relating to past directors.

Emoluments

These amounts comprise fees paid to the non-executive chair 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 116.

Directors' remuneration costs are borne by other undertakings within the group.

12. Employee costs and numbers

		$ million
Employee costs	2021	2020
Wages and salaries	**696**	814
Social security costs	**91**	119
Pension costs	**50**	90
	837	1,023

Average number of employees[a]	2021	2020
gas & low carbon energy	**276**	
oil production & operations	**161**	
customers & products	**1,039**	
other businesses and corporate	**1,772**	
	3,248	3,832

[a] Information for 2021 has been presented to reflect the changes in reportable segments. For more information see Note 1 Significant accounting policies, judgements, estimates and assumptions - Change in segmentation in the group financial statements. Comparative data for these new reportable segments is not available.

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.

13. Events after the reporting period

On 27 February 2022, following the military action in Ukraine, bp announced that it will exit its 19.75% shareholding in Rosneft Oil Company (Rosneft) a Russian oil and gas company. As of 27 February 2022, bp chief executive officer Bernard Looney also stepped down from the board of Rosneft with immediate effect and has submitted a letter of resignation as did the other Rosneft director nominated by bp, former bp group chief executive Bob Dudley. On the same date bp decided to exit its other businesses with Rosneft within Russia.

The decision to exit the shareholding in Rosneft and its other businesses with Rosneft within Russia, combined with the market impact on Russian assets that has arisen following the military action in Ukraine will have a material effect on the company's 2022 financial statements on the carrying amount of bp p.l.c.'s investment, held through BP International Limited, in BP Russian Investments Limited, which at 31 December 2021 stood at approximately $14.8 billion.

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14. Related undertakings of the group

In accordance with Section 409 of the Companies Act 2006, a full list of related undertakings, the registered office address and the percentage of equity owned as at 31 December 2021 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 stated ownership percentages represent the effective equity owned by the group.

Subsidiaries

Company by country and address of incorporation	Ownership interest	%
Albania		
Air BP Albania Sh.A., Aeroporti Nderkombetar i Tiranes, "Nene Tereza", Post Box 2933 in Tirana, Albania		
Air BP Albania SHA	Ordinary	100.00
Argentina		
Av. Cordoba 315 Piso 8, Buenos Aires, 1054, Argentina		
Latin Energy Argentina S.A.	Ordinary	100.00
Australia		
4 Sinclair Street, Mount Gambier, South Australia, 5290, Australia		
Open Energi Australia Pty Ltd	Ordinary A	100.00
Level 15, 240 St Georges Terrace, Perth, WA, 6000, Australia		
BP Developments Australia Pty. Ltd.	Ordinary	100.00
Level 17, 717 Bourke Street, Docklands VIC 3008, Australia		
Advance Petroleum Holdings Pty Ltd	Ordinary	100.00
Advance Petroleum Pty Ltd	Ordinary	100.00
Air Refuel Pty Ltd	Ordinary A; Ordinary B	100.00
Allgreen Pty Ltd	Ordinary	100.00
ARCO Resources Limited	Ordinary	100.00
BASS Holdings Trust	Membership Interest	51.00
BASS Management Pty Ltd	Ordinary	51.00
BASS NZ Head Trust	Membership Interest	51.00
BASS NZ Management Pty Ltd	Ordinary	100.00
BASS NZ Sub Management Pty Ltd	Ordinary	100.00
BASS NZ Sub Trust	Membership Interest	51.00
BP Australia Capital Markets Limited	Ordinary	100.00
BP Australia Employee Share Plan Proprietary Limited	Ordinary	100.00
BP Australia Group Pty Ltd	Ordinary; Preference	100.00
BP Australia Investments Pty Ltd	Ordinary	100.00
BP Australia Pty Ltd	Ordinary	100.00
BP Australia Shipping Pty Ltd[a]	Ordinary	100.00
BP Australia Supply Pty Ltd	Ordinary	100.00
BP Aviation Infrastructure Investment Pty Ltd	Ordinary	100.00
BP Bulwer Island Pty Ltd	Ordinary; Ordinary A; Ordinary B	100.00
BP Finance Australia Pty Ltd	Ordinary	100.00
BP Oil Australia Pty Ltd	Ordinary	100.00
BP Refinery (Kwinana) Proprietary Limited	Ordinary	100.00
BP Regional Australasia Holdings Pty Ltd	Ordinary	100.00
BP Solar Pty Ltd	Ordinary	100.00
BP Energy Australia Pty Ltd	Ordinary	100.00
Brian Jasper Nominees Pty Ltd	Ordinary	100.00
Burmah Castrol Australia Pty Ltd	Ordinary; Redeemable preference	100.00
Castrol Australia Pty. Limited	Ordinary	100.00
Castrol Holdings Australia Pty Ltd[b]	Ordinary	100.00
Centrel Pty Ltd	Ordinary	100.00
Clarisse Holdings Pty Ltd	Ordinary	100.00
Dermody Petroleum Pty. Ltd.	Ordinary	100.00
Elite Customer Solutions Pty Ltd	Ordinary	100.00
International Bunker Supplies Pty Ltd	Ordinary	100.00

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14. Related undertakings of the group – continued

No. 1 Riverside Quay Proprietary Limited	Ordinary	100.00
Taradadis Pty. Ltd.	Ordinary	100.00
West Kimberley Fuels Pty Ltd	Ordinary	100.00
Mazars, Level 11, 307 Queen Street, Brisbane, QLD, 4000, Australia		
Onyx Insight Australia Pty Ltd	Ordinary	100.00
Austria		
Straße 6, Objekt 17, Industriezentrum NÖ-Süd, 2355 Wr. Neudorf, Austria		
CASTROL Austria GmbH	Ordinary	100.00
Castrol Österreich Lubricants GmbH	Ordinary	100.00
Azerbaijan		
153 Neftchilar Avenue, Baku, AZ1010, Azerbaijan		
BP-AIOC Exploration (TISA) LLC	Membership Interest	65.88
TISA Education Complex LLC	Membership Interest	65.88
Bahamas		
2 Bayside Executive Park, West Bay, Nassau, Bahamas		
ARCO Trinidad Exploration and Production Company Limited	Ordinary	100.00
BP Exploration (El Djazair) Limited	Ordinary	100.00
Barbados		
The Financial Services Centre, Bishop's Court Hill, St. Michael, Barbados		
BP (Barbados) Holding SRL	Ordinary	100.00
BP Train 2/3 Holding SRL	Ordinary	100.00
Belgium		
Langerbruggekaai 18, Gent, 9000, Belgium		
BP Iraq N.V.	Ordinary	100.00
Castrol Belgium B.V.	Ordinary	100.00
Bermuda		
Washington House, 4th Floor, 16 Church Street, Hamilton HM 11, Bermuda		
BP LNG Shipping Limited	Ordinary	100.00
Brazil		
Avenida das Américas 3434, Bloco 7, Sala 301 a 308 (parte), Barra da Tijuca, Rio de Janeiro, 22640-102, Brazil		
BP Brasil Ltda.	Ordinary	100.00
BP Energy do Brasil Ltda.	Ordinary	100.00
Castrol Brasil Ltda.	Ordinary	100.00
Avenida das Nações Unidas, 12399, rooms 62,63 and 64 size B, 6th floor, Landmark Building, São Paulo, 04578-000, Brazil		
BP Comercializadora de Energia Ltda.	Ordinary	100.00
Avenida das Nações Unidas, nº 12.399, 4º andar, salas 43 e 44 - Parte, Lado A, Brooklin Paulista,São Paulo/SP, CEP 04578-000, Brazil		
Air BP Brasil Ltda.	Ordinary	100.00
Avenida das Nações Unidas, No. 12.399, 4th floor, rooms 43A and 44A , Tower C, Building Landmark, Brooklin Paulista, São Paulo, 04578-000, Brazil		
BP Biocombustíveis S.A.	Ordinary	96.53
Avenida Tamboré, 448, Sao Paulo, Barueri, 06460-000, Brazil		
Castrol Servicos Ltda.	Ordinary	100.00
British Virgin Islands		
Craigmuir Chambers, P.O. Box 71, Road Town, Tortola, British Virgin Islands		
Amoco Bolivia Services Company Inc.	Ordinary	100.00
BP Egypt East Delta Marine Corporation	Ordinary; Preference	100.00
BP Middle East Enterprises Corporation	Ordinary	100.00
Jayla Place, Wickhams Cay 1, PO Box 3190,Tortola, Road Town, VG1110, British Virgin Islands		
Wiriagar Overseas Ltd	Ordinary	100.00
Canada		
1100, 635 - 8th Avenue SW, Calgary AB T2P 3M3, Canada		
Terre de Grace Partnership	Partnership interest	75.00
240 - 4th Avenue SW, Calgary AB T2P 4H4, Canada		
563916 Alberta Ltd.	Preference	99.99
Dome Beaufort Petroleum Limited	Ordinary	100.00
Dome Wallis (1980) Limited Partnership	Partnership interest	92.50
Fotech Solutions (Canada) Ltd.	Membership Interest	100.00

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14. Related undertakings of the group – continued

421 7 Avenue Sw, Suite 1700, Calgary AB T2P 4K9, Canada		
Finite Carbon Canada Ltd	Ordinary	100.00
Stewart McKelvey, Attention: Lawrence J. Stordy, 900, 1959 Upper Water Street, Halifax, NS, B3J 3N2, Canada		
BP Canada Energy Development Company	Ordinary	100.00
BP Canada Energy Group ULC	Ordinary	100.00
Chile		
Av. Américo Vespucio Sur No. 100, of. 1101, Las Condes, Santiago, Chile		
Burmah Chile SpA	Ordinary	100.00
China		
1-3 / F, Unit D2,1958 Double Innovation Park, No. 220, Huashan Road, Zhongyuan District, Zhengzhou City, China		
Zhenzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
302,252, Duxin North Road, Fotang Town, Yiwu City, Zhejiang Province, China		
Jinhua BP Xiaoju New Energy Technology Co., Ltd.	Membership Interest	70.00
C10, Office card position, Zhongfafa Maker Space, Room 515, Building A, No. 19, Nanxiang Third Road, Guangzhou City, Huangpu District, China		
Guangzhou Huangpu BP Xiaoju New Energy Technology Co., Ltd.	Membership Interest	70.00
D69, Floor 3, Block 1, Phase 6,Tianan Nanhai Digital New Town, No.12, Jianping Road, Guicheng Street, Nanhai District, Foshan city, China		
Foshan BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Fenglin West Road, Dongpu Street,Yuecheng District, Shaoxing City, Zhejiang Province, China		
Shaoxing BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Floor 3, Building 5, 255 Guiqiao Road, Shanghai Pilot Free Trade Zone, China		
Castrol (Shanghai) Management Co., Ltd	Membership Interest	100.00
Floor 3, No. 7, Building 2, Zhucun Village, Sanjiang Street, Wucheng District, Jinhua, Zhejiang Province, China		
Jinhua BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
No 833, South Guang Zhou Avenue, Guangzhou Province, Haizhu District, China		
BP Guangdong Limited	Membership Interest	90.00
No. 399 Dongfeng highway, Dongping Town, Chongming District, (Dongping Economic Development, Shanghai City, China		
Shanghai Quanzhi New Energy Co., Ltd.	Membership Interest	70.00
No.1120 Mawan Road, Nanshan District, Shenzhen, China		
Castrol (Shenzhen) Company Limited	Membership Interest	100.00
No.17-5, Second Floor 04, Sumitomo Homeland, Binhu District, Wuxi City, China		
Wuxi BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
No.25 (unit 111A), Beiqiao Road, Shiqiao Street,Guangzhou City, Panyu District, PRC, China		
Guangzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
No.9 Bin Jiang South Road, Petrochemical Industrial Park, Taicang Gangkou Development Zone, Jiangsu Province, China		
BP (China) Industrial Lubricants Limited	Membership Interest	100.00
Room 1001, 10th Floor, Building A2, Xiangjiang Times Business Square, No.179 Xiandao Road, Yuelu District,Hunan, Changsha, China		
BP (Hunan) Petroleum Company Limited	Membership Interest	100.00
Room 1001, 2nd Floor, Building 1,Qinqiao Agricultural Innovation Headquarters Building, Xiash, Shiyang Town, Taishun County, Wenzhou City, Zhejiang Province, China		
Wenzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room 105-72746 (Centralized office area), No.6 Baohua Road, Zhuhai City, Hengqin New District, China		
Zhuhai BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room 1-2201, Sijian Meilin Mansion, No. 48-15 Wuyingshan Middle Road, Tianqiao District, Shandong, Ji'nan, China		
BP (Shandong) Petroleum Co., Ltd	Membership Interest	100.00
Room 1908, YOUYOU International Plaza, Pudong District, Shanghai, China		
BP (Shanghai) Technology Company Limited	Membership Interest	100.00
Room 201, Complex A, Qianwan Road 1, Qianhai Shenzhen-Hong Kong Cooperation Zone, Shenzhen City, China		
BP Xiaoju New Energy (Shenzhen) Co., Ltd.	Membership Interest	70.00
Room 2101, 21F Youyou International Plaza, 76 Pujian Road, Pudong, Shanghai Pilot Free Trade Zone, China		
BP (China) Holdings Limited	Membership Interest	100.00
Room 2103, 10 Hua Xia Road, Tianhe District, Guangzhou, PR, China		
BP (Guangzhou) Advanced Mobility Limited	Membership Interest	100.00
Room 2-1-7, 1st Floor,Building 7, No.130 Xiazhong Dukou, Shapingba District, Chongqing, China		
Chongqing BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00

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14. Related undertakings of the group – continued

Room 222-1, Building 1, Wanya Famous City, Qiantang New District, Hangzhou City, Zhejiang Province, China		
Hangzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room 2305, Floor 20, Building 29,Yard 8, West Cultural Park Road, Beijing Economic and Technological Development Zone, Beijing, China		
Beijing BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room 2-521, Building A,No.6 Huafeng Road, Huaming Hi-tech Industrial Zone, Dongli District, Tianjin city, China		
Tianjin BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room 309, 3rd Floor, 2nd Floor, Southwest International Business Port, West Square, Taiyuan South Station, Taiyuan City, Xiandian District, China		
Taiyuan BP Xiaoju New Energy Technology Co., Ltd.	Membership Interest	70.00
Room 3173, Building 1,No.39 Hongtu Road, Nancheng Street, Dongguan City, Guangdong Province, China		
Dongguan BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room 3726, Building 3, No. 89 Shuanggao Road, Gaochun Economic Development Zone, Nanjing, Gaochun District, China		
Nanjing BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room 421, Floor 4,Building 8, No. 388, North Section of Yizhou Avenue, High-tech Zone, Chengdu city, China		
Chengdu BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room 703, Building 32, No.258 Shengpu Road, Suzhou Industrial Park, China		
Suzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room 708-168, 7th Floor, Building C,Hangchuang Plaza, Shenzhou 4th Road, National Civil Aerospace Industry Base, Xi'an, Shaanxi, China		
Xi'an BP Xiaoju New Energy Technology Co., Ltd.	Membership Interest	70.00
Room 7088-594, 7th Floor, 1558 Jiangnan Road, Ningbo High-tech Zone, Zhejiang Province, China		
Ningbo BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room 716, Block C, Future Science and Technology Plaza, No.136, Xiuzhou Avenue, Xincheng Street, Zhejiang Province, Jiaxing City, China		
Jiaxing BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room -829, 1st Floor, D2 District, Fuxing City, No. 32 Binhai Avenue, Binhai Street, Longhua District, Haikou City, Hainan Province, China		
Hainan BP Xiaoju New Energy Co., Ltd	Membership Interest	70.00
South of NanGang Industrial Area, and East of Hai Gang Road, Tianjin Economic Development Area, Tianjin, China		
Castrol (Tianjin) Lubricants Co., Ltd	Membership Interest	100.00
Unit 03A, 33rd Floor, T1 Building, IFC, No.188, Jiefang West Road, Dingwangtai Street, Changsha City, Furong District, China		
Changsha BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Colombia		
Calle 80 No.11-42 Oficina 901, Bogota, 110111, Colombia		
GOAM 1 C.I S. A .S	Ordinary	100.00
Calle 81, No 11 - 42, Oficina 901, Torre Sur, Bogota, Colombia		
Castrol Colombia Ltda.	Ordinary	100.00
Croatia		
Savska cesta 32, Zagreb, Croatia		
Air BP Croatia d.o.o.	Ordinary	100.00
Denmark		
c/o Danish Refuelling Services I/S, Hydrantvej 16, 2770 Kastrup, Denmark		
BP Aviation A/S	Ordinary	100.00
Orestads Boulevard 73, Kobenhavn S, 2300, Denmark		
BP Danmark A/S	Ordinary	100.00
Nordic Lubricants A/S	Ordinary	100.00
Egypt		
No. 28, First Sector, City Center, Cairo, New Cairo, Egypt		
BP Marketing Egypt LLC	Ordinary	100.00
Castrol Egypt Lubricants S.A.E.	Ordinary	51.00
Estonia		
Harju maakond, Lasnamäe linnaosa, Väike-Sõjamäe tn 12a,11415, Tallinn, Estonia		
Eesti Aviokütuse Teenuste AS	Ordinary	50.00
Faroe Islands		
Krosslíð 11, FO-100 Tórshavn, Faroe Islands		
Sp/f Decision3 (GreenSteam) Company	Ordinary B (92.31%); Ordinary D (78.43%)	54.77

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14. Related undertakings of the group – continued

Finland		
Öljytie 4, 01530 Vantaa, Finland		
Air BP Finland Oy	Ordinary	100.00
France		
Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, Cergy Cedex, 95863, France		
BP France	Ordinary	100.00
Castrol France Sas	Ordinary	100.00
PRODUITS METALLURGIE DOITTAU	Ordinary	100.00
Société de Gestion de Dépots d'Hydrocarbures - GDH	Ordinary	100.00
SRHP	Ordinary	100.00
Gambia		
3 Kairaba Avenue, 3rd Floor Centenary, Kanifing Municipality, Serekunda West, Gambia		
BP Exploration (Gambia) Limited	Ordinary	100.00
Germany		
Alexander-von-Humboldt-Straße 1, Gelsenkirchen, 45896, Germany		
Gelsenkirchen Raffinerie Netz GmbH	Ordinary	100.00
Ruhr Oel GmbH (ROG)	Ordinary	100.00
Erkelenzer Straße 20, 41179 Mönchengladbach, Germany		
Castrol Industrie und Service GmbH	Ordinary	100.00
Timmerhellstsr. 28, Mülheim/Ruhr, 45478, Germany		
DHC Solvent Chemie GmbH	Ordinary	100.00
Überseeallee 1, 20457, Hamburg, Germany		
BP Europa SE[c]	Ordinary	100.00
BP Holdings Central Europe B.V.	Ordinary	100.00
BP Lingen Green Hydrogen Verwaltung GmbH	Ordinary	100.00
BP Olex Fanal Mineralol GmbH	Ordinary	100.00
Castrol Deutschland Verwaltungsgesellschaft mbH	Ordinary	100.00
Castrol Germany GmbH	Ordinary	100.00
Wittener Straße 45, 44789 Bochum, Germany		
Aral Aktiengesellschaft	Ordinary	100.00
Aral Pulse GmbH	Ordinary	100.00
B2Mobility GmbH	Ordinary	100.00
BP Fuels Deutschland GmbH	Ordinary	100.00
BP Green Hydrogen Management GmbH	Ordinary	100.00
Ghana		
PwC Tower, A4 Rangoon Lane, Cantonments City, PMB CT 42 Cantonments, Accra, Ghana		
BP Ghana Limited	Ordinary	100.00
Greece		
1, Proteos & 51, Anapafseos str, 15235 Vrilissia, Attica, Greece		
RAPI SA	Ordinary	62.51
26A Ioannou Apostolopoulou, Halandri, Attica, Athens, 152 31, Greece		
BP Oil Hellenic S.A.	Ordinary	100.00
Castrol Hellas Single Member Societe Anonyme	Ordinary	100.00
Guernsey		
Albert House, South Esplanade, St. Peter Port, GY1 1AW, Guernsey		
BP Pensions (Overseas) Limited[d]	Ordinary	100.00
Jupiter Insurance Limited	Ordinary	100.00
Hong Kong		
Unit 25-150, 25/f, Two Harbour Square,Kowloon, 180 Wai Yip Street, Kwun Tong, Hong Kong		
BP Hong Kong Limited	Ordinary	100.00
Castrol (China) Limited	Ordinary	100.00
Hungary		
1133 Budapest, Árbóc utca 1-3, Hungary		
BP Business Service Centre KFT	Membership Interest	100.00
Iceland		
Skogarhlid 12, 105, Reykjavik, Iceland		
Air BP Iceland	Ordinary	100.00

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14. Related undertakings of the group – continued

India		
2nd,3rd & 4th Floor, 201,301,401, Bldg. No. 6, R4, KRC Infrastructure & Projects Pvt. Ltd. SEZ, Kharadi, Pune, India, 411014		
BP Business Solutions India Private Limited	Ordinary	100.00
Office No. 306, Regus Business Center , 3rd Floor, Abbusali St, Saligramam, Chennai, Tamil Nadu, 600093, India		
OnSight Analytics Solutions India Private Ltd.	Ordinary	100.00
Technopolis Knowledge Park, Mahakali Caves Road, Andheri (East), Mumbai 400093, India		
BP India Private Limited	Ordinary	88.65
Castrol India Limited	Ordinary	51.00
Indonesia		
Arkadia Green Park Tower G, 2nd Floor, Jl. Letjend TB Simatupang Kav. 88, Jakarta Selatan, Pasar Minggu, 12520, Indonesia		
PT Jasatama Petroindo	Ordinary A; Ordinary B	100.00
Arkadia Green Park, Tower G, 3rd floor, Jl. Let. Jen. TB Simatupang Kav. 88, Jakarta Selatan, DKI Jakarta, Jakarta 12520, Indonesia		
PT Castrol Indonesia	Ordinary	68.30
JL. Raya Merak KM 117,DS Gerem, Gerem Grogol, Banten, Cilegon, Indonesia		
PT Castrol Manufacturing Indonesia	Ordinary	68.30
Iraq		
Khur Al-Zubair, pear No 1, Basra, Iraq		
Water Way Trading and Petroleum Services LLC	Ordinary	100.00
Royal Tulip Al Rasheed Hotel, Baghdad Tower, PO Box 8070, Baghdad, Iraq		
Phoenix Petroleum Services, Limited Liability Company	Ordinary	100.00
Ireland		
One Spencer Dock, North Wall Quay, Dublin 1, Ireland		
Castrol (Ireland) Limited	Ordinary	100.00
Italy		
Piazza Borromeo, 12, Milano, 20123, Italy		
BP Italia Holdings SpA	Ordinary	100.00
Via Verona 12, Cornaredo, Milan, 20010, Italy		
BP Italia SpA	Ordinary	100.00
Japan		
15th Fl. Roppongi Hills Mori Tower, 10-1 Roppongi 6-chome, Minato-ku, Tokyo106-6115, Japan		
BP Japan K.K.	Ordinary	100.00
TJKK	Ordinary	100.00
East Tower 20F, Gate City Ohsaki, 1-11-2 Osaki, Shinagawa-ku, Tokyo, Japan		
BP Castrol KK	Ordinary	64.84
BP Lubricants KK	Ordinary	64.84
Castrol KK	Ordinary	64.84
Korea (the Republic of)		
19th Floor, 302, Teheran-ro, Gangnam-gu, Seoul, Korea (the Republic of)		
BP Korea Limited	Ordinary	100.00
504-ho, 213-3, Cheomdan-ro, Jeju-do, Jeju-si, Korea (the Republic of)		
Onyx Insight Korea Co., Ltd.	Ordinary	100.00
Lebanon		
P O Box - 11 -5814c/o Coral Oil Building, 583, Avenue de Gaulle, Raoucheh, Beirut, Lebanon		
Lebanese Aviation Technical Services S.A.L.	Ordinary	100.00
Luxembourg		
Bâtiment B, 36 route de Longwy, L-8080 Bertrange, Luxembourg		
Aral Luxembourg S.A.	Ordinary	100.00
Aral Tankstellen Services Sarl	Ordinary	100.00
Malaysia		
Level 9, Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, Kuala Lumpur, 59200, Malaysia		
Aspac Lubricants (Malaysia) Sdn. Bhd.	Ordinary	63.03
BP Business Service Centre Asia Sdn Bhd	Ordinary	100.00
BP Castrol Lubricants (Malaysia) Sdn. Bhd.	Ordinary	63.03
BP Malaysia Holdings Sdn. Bhd.	Ordinary	70.00
Mexico		
Av. Santa Fe No. 505 Piso 10, Col. Cruz Manca Santa Fe, Deleg. CuajimalpaC.P., 05349 México D.F., Mexico		
BP Energía México, S. de R.L. de C.V.	Ordinary; Ordinary B	100.00

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14. Related undertakings of the group – continued

BP Estaciones y Servicios Energéticos, Sociedad Anónima de Capital Variable	Ordinary A; Ordinary B	100.00
BP Exploration Mexico, S.A. De C.V.	Ordinary A; Ordinary B	100.00
BP Servicios de Combustibles S.A. de C.V.	Ordinary	100.00
BP Servicios territoriales, S.A. de C.V.	Ordinary	100.00
Castrol Mexico, S.A. de C.V.	Ordinary A; Ordinary B	100.00
Mes Tecnologia En Servicios Y Energia, S.A. De C.V.	Ordinary A; Ordinary B	100.00
Mozambique		
Society and Geography Avenue, Plot No. 269 , Third floor, Maputo, Mozambique		
BP Mocambique Limitada	Ordinary	100.00
Netherlands		
d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands		
Actomat B.V.	Ordinary	100.00
Amoco Canada International Holdings B.V.	Ordinary	100.00
Amoco Chemicals (FSC) B.V.	Ordinary	100.00
Amoco Exploration Holdings B.V.	Ordinary	100.00
Amoco Trinidad Gas B.V.	Ordinary	100.00
BP Angola (Block 18) B.V.	Ordinary	100.00
BP Canada International Holdings B.V.	Ordinary	100.00
BP Commodity Supply B.V.	Ordinary	100.00
BP Egypt East Tanka B.V.	Ordinary	100.00
BP Egypt Production B.V.	Ordinary	100.00
BP Egypt Ras El Barr B.V.	Ordinary	100.00
BP Egypt West Mediterranean (Block B) B.V.	Ordinary	100.00
BP Energy Solutions B.V.	Ordinary	100.00
BP Holdings B.V.	Ordinary	100.00
BP Holdings International B.V.	Ordinary	100.00
BP Management International B.V.	Ordinary	100.00
BP Management Netherlands B.V.	Ordinary	100.00
BP Muturi Holdings B.V.	Ordinary	100.00
BP Nederland Holdings B.V.	Ordinary	100.00
BP Netherlands Upstream B.V.	Ordinary	100.00
BP Raffinaderij Rotterdam B.V.	Ordinary	100.00
BPNE International B.V.	Ordinary	100.00
Castrol B.V.	Ordinary	100.00
Castrol Holdings Europe B.V.	Ordinary	100.00
Castrol Nederland B.V.	Ordinary	100.00
Foseco Holding International B.V.	Ordinary	100.00
FreeBees B.V.	Ordinary	100.00
Windpark Energy Nederland B.V.	Ordinary	100.00
New Zealand		
Watercare House, 73 Remuera Road, Rumuera, Auckland, 1050, New Zealand		
BP New Zealand Holdings Limited	Ordinary	100.00
BP New Zealand Share Scheme Limited	Ordinary	100.00
BP Oil New Zealand Limited	Ordinary	100.00
BP Pacific Investments Ltd	Ordinary	100.00
Castrol New Zealand Limited	Ordinary	100.00
Coro Trading NZ Limited	Ordinary	100.00
Europa Oil NZ Limited	Ordinary	100.00
Nigeria		
1, Oyinka Abayomi Drive, Ikoyi, Lagos, Nigeria		
BP Exploration (Nigeria) Limited	Ordinary	100.00
188, Awolowo Road, S. W. Ikoyi, Lagos, Nigeria		
Amoco Nigeria Exploration Company Limited	Ordinary; Preference	100.00
Amoco Nigeria Oil Company Limited	Membership Interest	100.00
Amoco Nigeria Petroleum Company Limited	Membership Interest	100.00
8/10, Broad Street, Lagos, Nigeria		
ARCO Oil Company Nigeria Unlimited	Membership Interest	100.00
Heritage Place, 13th Floor, 21 Lugard Avenue,Lagos, Ikoyi, Nigeria		
BP Global West Africa Limited	Ordinary	100.00

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14. Related undertakings of the group – continued

Norway		
Tjuvholmen allé 3, 0252 Oslo, Norway		
Air BP Norway AS	Membership Interest	100.00
BP Fuels & Lubricants AS	Ordinary	100.00
Oman		
PO Box 2309, Salalah, 211, Oman		
BP Global Investments Salalah & Co LLC	Ordinary	100.00
Pakistan		
D-67/1, Block # 4, Scheme # 5, Clifton, Karachi, Pakistan		
Castrol Pakistan (Private) Limited	Ordinary	100.00
Peru		
Av. Camino Real, 111 Torre B Oficina, 603 San Isidro, Lima, Peru		
Castrol Del Peru S.A.	Ordinary	100.00
Philippines		
32/F LKG Tower, Ayala Avenue, Makati City, 6801, Philippines		
Castrol Philippines, Inc.	Ordinary	100.00
Poland		
ul. Grzybowska 62, Warszawa, 00-844, Poland		
Castrol CEE spólka z ograniczoną odpowiedzialnością	Ordinary	100.00
ul. Pawia 9, Małopolskie, Kraków, 31-154, Poland		
BP Polska Services Sp. z o.o.	Membership Interest	100.00
Portugal		
Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal		
BP Portugal -Comercio de Combustiveis e Lubrificantes SA	Ordinary	100.00
Castrol Portugal, S.A.	Ordinary	100.00
Fuelplane- Sociedade Abastecedora De Aeronaves, Unipessoal, Lda	Ordinary	100.00
Sociedade de Promocao Imobiliaria Quinta do Loureiro, SA	Ordinary	100.00
Romania		
59 Aurel Vlaicu Street, Otopeni, Ilfov County, Romania		
Air BP Sales Romania S.R.L.	Ordinary	100.00
Bucharest, District 3, Boulevard Comeliu Coposu, no 6-8, Unirii View Building, Office 101, floor 1, Romania		
Castrol Lubricants RO S.R.L	Ordinary	100.00
Russian Federation		
2 Paveletskaya sq, Building1, 115054 Moscow, Russian Federation		
Limited liability company Setra Lubricants	Membership Interest	100.00
Novinskiy blvd.8, 17th floor, premises 11, Moscow, 121099, Russian Federation		
Limited Liability Company BP Toplivnaya Kompania	Membership Interest	100.00
Novinskiy blvd.8, 18th floor, office 14, Moscow, 121099, Russian Federation		
OOO BP STL	Membership Interest	100.00
Senegal		
Route de Ouakam x Corniche Ouest, Immeuble Alphadio Barry, Dakar, Senegal		
BP Oil Senegal S.A.	Ordinary	100.00
Singapore		
7 Straits View #26-01, Marina One East Tower, 018936, Singapore		
BP Asia Pacific Pte Ltd[b]	Ordinary	100.00
BP Energy Asia Pte. Limited	Ordinary	100.00
BP Exploration (Xazar) Pte. Ltd.	Ordinary	100.00
BP Maritime Services (Singapore) Pte. Limited	Ordinary	100.00
BP Singapore Pte. Limited	Ordinary	100.00
Castrol Singapore PTE. Limited	Ordinary	100.00
South Africa		
199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, GP, 2196, South Africa		
BP Southern Africa Proprietary Limited	Ordinary	74.89
Burmah Castrol South Africa (Pty) Limited	Ordinary; Ordinary A	100.00
ECM Markets SA (Pty) Ltd	Ordinary	74.89
Masana Petroleum Solutions (Pty) Ltd	Ordinary	38.77
Spain		
Atraque Punta Lucero, Explanada Punta Ceballos s/n, Ziérbena (Vizcaya), Spain		
Bahia de Bizkaia Electridad, S.L.	Ordinary	75.00

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14. Related undertakings of the group – continued

Avenida de la Transición Española 30, Parque Empresarial Omega, Edificio D. 28108 Alcobendas, Madrid, Spain		
BP Energy Solutions Sociedad de Valores, S.A	Ordinary	100.00
BP Espana, S.A. Unipersonal	Ordinary A; Ordinary B; Ordinary C	100.00
BP Gas Europe, S.A.U.	Ordinary	100.00
BP Solar Espana, S.A. Unipersonal	Ordinary A; Ordinary B	100.00
Castrol España, S.L. Sociedad Unipersonal	Ordinary	100.00
Markoil, S.A. Unipersonal	Ordinary	100.00
Onyx Insight Spain Sociedad Limitada	Ordinary	100.00
Polígono Industrial "El Serrallo", s/n 12100 Grao de Castellón, Castellón de la Plana, Spain		
BP Oil Espana, S.A. Unipersonal	Ordinary	100.00
Sweden		
Box 8107, Stockholm, 10420, Sweden		
Air BP Sweden AB	Ordinary	100.00
Hemvärnsgatan, 171 54, Solna, Sweden		
Nordic Lubricants AB	Ordinary	100.00
Switzerland		
Baarerschtrasse 139, Zug, 6300, Switzerland		
Castrol Switzerland GmbH	Ordinary	100.00
Taiwan		
7FNo. 71Sec. 3Min Sheng East Road, Taipei, Taiwan		
BP Taiwan Marketing Limited	Ordinary	100.00
Thailand		
23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand		
BP - Castrol (Thailand) Limited	Ordinary A	57.59
SOFAST Limited	Ordinary (100.00%); Preference (58.99%)	63.09
39/77-78 Moo 2 Rama II Road, Tambon Bangkrachao, Amphur Muang, Samutsakorn 74000, Thailand		
BP Holdings (Thailand) Limited	Ordinary (80.10%); Preference (99.07%)	81.18
BP Oil (Thailand) Limited	Ordinary (93.64%); Preference (81.18%)	90.40
Trinidad and Tobago		
5-5A Queen's Park West, Port-of-Spain, Trinidad and Tobago		
BP Alternative Energy Trinidad and Tobago Limited	Ordinary	100.00
BP Trinidad Processing Limited	Ordinary	100.00
Mayaro Initiative for Private Enterprise Development	Ordinary	70.00
Turkey		
Degirmen yolu cad. No:28, Asia OfisPark K:3 Icerenkoy-Atasehir, Istanbul, 34752, Turkey		
BP Akaryakit Ortakligi	Partnership interest	70.00
BP Dogal Gaz Ticaret Anonim Sirketi	Ordinary	100.00
BP Petrolleri Anonim Sirketi	Ordinary	100.00
Içerenköy Mah, Degirmen Yolu Cad, Mengerler Blok No: 28/1 Iç Kapi No: 12, Atasehir/Istanbul, Turkey		
Castrol Madeni Yağlar Ticaret Anonim Şirketi	Ordinary	100.00
United Arab Emirates		
Jebel Ali Free Zone, Dubai, United Arab Emirates		
Stryde Middle East FZE	Ordinary	100.00
P.O.Box 1699, Dubai, 1699, United Arab Emirates		
BP Middle East LLC	Ordinary	100.00
United Kingdom		
1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom		
BP Amoco Exploration (In Amenas) Limited	Ordinary	100.00
BP Energy Europe Limited	Ordinary	100.00
BP Exploration Company Limited	Ordinary	100.00
Britannic Strategies Limited	Ordinary	100.00
Britoil Limited	Ordinary	100.00
Burmah Castrol PLC[b]	Ordinary	100.00
The Burmah Oil Company (Pakistan Trading) Limited	Ordinary	100.00
10 Upper Berkeley Street, London, W1H 7PE, United Kingdom		
Horizon 38 Management Company Limited	Membership Interest	53.50

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14. Related undertakings of the group – continued

11 Black Horse Lane, Ipswich, Suffolk, IP1 2EF, United Kingdom		
Manormaker (Nominee No. 1) Limited	Ordinary	99.90
Manormaker (Nominee No. 2) Limited	Ordinary	99.90
Manormaker GP Limited	Membership Interest	99.90
The Manormaker Limited Partnership	Membership Interest	99.90
33 Cavendish Square, London, W1G 0PW, United Kingdom		
Ropemaker Exempt Unit Trust	Membership Interest	100.00
55 Baker Street, London, W1U 7EU, United Kingdom		
BP Containment Response Limited	Ordinary	100.00
BP Exploration (Nigeria Finance) Limited	Ordinary	100.00
BP Exploration Mexico Limited	Ordinary	100.00
Charging Solutions Limited	Ordinary	100.00
5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS, United Kingdom		
British Pipeline Agency Limited	Ordinary A	50.00
Abbey Gardens, 7th Floor, 4 Abbey Street, Reading, RG1 3BA, United Kingdom		
Autino Holdings Limited	Ordinary A; Ordinary B; Ordinary D	88.85
Autino Limited	Ordinary	88.85
Breckland, Linford Wood, Milton Keynes, MK146GY, United Kingdom		
Charge Your Car Limited	Ordinary A; Ordinary B	100.00
Chargemaster Limited	Ordinary	100.00
Elektromotive Limited	Ordinary	100.00
C/O Bdo Llp, 5 Temple Square, Temple Street, Liverpool, L2 5RH, United Kingdom		
BP Exploration (Canada) Limited	Ordinary	100.00
BP Subsea Well Response (Brazil) Limited	Ordinary	100.00
Expandite Contract Services Limited	Ordinary	100.00
Grampian Aviation Fuelling Services Limited (In Liquidation)	Ordinary	100.00
Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom		
Air BP Limited	Ordinary	100.00
Amoco (Fiddich) Limited	Ordinary	100.00
Amoco U.K. Petroleum Limited	Ordinary	100.00
Atlantic 2/3 UK Holdings Limited	Ordinary	100.00
BP (Abu Dhabi) Limited	Ordinary	100.00
BP (Barbican) Limited[b]	Ordinary	100.00
BP (Gibraltar) Limited	Ordinary	100.00
BP (GTA Mauritania) Finance Limited	Ordinary	100.00
BP (GTA Senegal) Finance Limited	Ordinary	100.00
BP (Indian Agencies) Limited[b]	Ordinary	100.00
BP Absheron Limited	Ordinary	100.00
BP Advanced Mobility Limited	Ordinary	100.00
BP Africa Limited[b]	Ordinary	100.00
BP Africa Oil Limited	Ordinary	100.00
BP Alternative Energy Holdings Limited	Ordinary	100.00
BP Alternative Energy Investments Limited	Ordinary	100.00
BP America Limited	Ordinary	100.00
BP Amoco Exploration (Faroes) Limited	Ordinary	100.00
BP Andaman II Ltd	Ordinary	100.00
BP Asia Pacific Holdings Limited	Ordinary	100.00
BP Australia Swaps Management Limited	Ordinary	100.00
BP Benevolent Fund Trustees Limited[b]	Ordinary	100.00
BP Biofuels Brazil Investments Limited	Ordinary	100.00
BP Capital Markets B.V.	Ordinary	100.00
BP Capital Markets p.l.c.	Ordinary	100.00
BP Car Fleet Limited[b]	Ordinary	100.00
BP Carbon Trading Limited	Ordinary	100.00
BP CCUS UK LTD	Ordinary	100.00
BP Chemicals East China Investments Limited	Ordinary	100.00
BP Chemicals Limited	Ordinary	100.00
BP Continental Holdings Limited	Ordinary	100.00

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14. Related undertakings of the group – continued

BP Corporate Holdings Limited	Ordinary	100.00
BP D230 Limited	Ordinary	100.00
BP East Kalimantan CBM Limited	Ordinary	100.00
BP Eastern Mediterranean Limited	Ordinary	100.00
BP Energy Colombia Limited	Ordinary	100.00
BP Exploration (Absheron) Limited	Ordinary	100.00
BP Exploration (Algeria) Limited	Ordinary	100.00
BP Exploration (Alpha) Limited	Ordinary; Debentures	100.00
BP Exploration (Angola) Limited	Ordinary	100.00
BP Exploration (Azerbaijan) Limited	Ordinary	100.00
BP Exploration (Caspian Sea) Limited	Ordinary	100.00
BP Exploration (D230) Limited	Ordinary	100.00
BP Exploration (Delta) Limited	Ordinary	100.00
BP Exploration (Epsilon) Limited	Ordinary	100.00
BP Exploration (Greenland) Limited	Ordinary	100.00
BP Exploration (Madagascar) Limited	Ordinary	100.00
BP Exploration (Morocco) Limited	Ordinary	100.00
BP Exploration (Namibia) Limited	Ordinary	100.00
BP Exploration (Psi) Limited	Ordinary	100.00
BP Exploration (Shafag-Asiman) Limited	Ordinary	100.00
BP Exploration (Shah Deniz) Limited	Ordinary	100.00
BP Exploration (South Atlantic) Limited	Ordinary	100.00
BP Exploration (STP) Limited	Ordinary	100.00
BP Exploration Angola (Kwanza Benguela) Limited	Ordinary	100.00
BP Exploration Argentina Limited	Ordinary	100.00
BP Exploration Beta Limited	Ordinary	100.00
BP Exploration China Limited	Ordinary	100.00
BP Exploration Company (Middle East) Limited	Ordinary	100.00
BP Exploration Indonesia Limited	Ordinary	100.00
BP Exploration Libya Limited	Ordinary	100.00
BP Exploration North Africa Limited	Ordinary	100.00
BP Exploration Operating Company Limited	Ordinary	100.00
BP Exploration Orinoco Limited	Ordinary	100.00
BP Exploration Personnel Company Limited	Ordinary	100.00
BP Exploration Peru Limited	Ordinary	100.00
BP Express Shopping Limited	Ordinary	100.00
BP Finance p.l.c.	Ordinary	100.00
BP Gas & Power Investments Limited	Ordinary	100.00
BP Gas Marketing Limited	Ordinary	100.00
BP Global Investments Limited[b]	Ordinary	100.00
BP Global Solutions Limited	Ordinary	100.00
BP Greece Limited	Ordinary	100.00
BP Holdings Canada Limited[b]	Ordinary	100.00
BP Holdings Iraq Ltd	Ordinary	100.00
BP Holdings North America Limited[b]	Ordinary; Cumulative redeemable preference	100.00
BP Indonesia Investment Limited	Ordinary	100.00
BP Integrated Solutions Limited	Ordinary	100.00
BP International Limited[b]	Ordinary	100.00
BP Investment Management Limited	Ordinary	100.00
BP Investments Asia Limited	Ordinary	100.00
BP Iran Limited	Ordinary	100.00
BP Kuwait Limited	Ordinary	100.00
BP Low Carbon Development Company Limited	Ordinary	100.00
BP Marine Limited	Ordinary	100.00
BP Mauritania Investments Limited	Ordinary	100.00
BP Middle East Limited[b]	Ordinary	100.00
BP Mocambique Limited	Ordinary	100.00
BP New Ventures Middle East Limited	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 282-336 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	Ordinary	100.00
BP Oil Kent Refinery Limited (in liquidation)	Ordinary	100.00
BP Oil Llandarcy Refinery Limited	Ordinary	100.00
BP Oil Logistics UK Limited	Ordinary	100.00
BP Oil UK Limited	Ordinary; Debentures	100.00
BP Oil Venezuela Limited	Ordinary	100.00
BP Oil Vietnam Limited	Ordinary	100.00
BP Oil Yemen Limited	Ordinary	100.00
BP Pension Escrow Limited	Ordinary	100.00
BP Pension Trustees Limited[b]	Ordinary	100.00
BP Pensions Limited[b]	Ordinary	100.00
BP Petrochemicals India Investments Limited	Ordinary	100.00
BP Pipelines (BTC) Limited	Ordinary	100.00
BP Pipelines (SCP) Limited	Ordinary	100.00
BP Pipelines (TANAP) Limited	Ordinary	100.00
BP Pipelines TAP Limited	Ordinary	100.00
BP Poseidon Limited	Ordinary	100.00
BP Properties Limited[b]	Ordinary	100.00
BP Retail Properties Limited	Ordinary	100.00
BP Russian Investments Limited	Ordinary	100.00
BP Russian Ventures Limited	Ordinary	100.00
BP Scale Up Factory Limited	Ordinary	100.00
BP Senegal Investments Limited	Ordinary	100.00
BP Services International Limited	Ordinary	100.00
BP Shafag-Asiman Limited	Ordinary	100.00
BP Shipping Limited	Ordinary	100.00
BP South America Holdings Ltd	Ordinary	100.00
BP Subsea Well Response Limited	Ordinary	100.00
BP Technology Ventures Limited	Ordinary	100.00
BP Turkey Refining Limited[b]	Ordinary	100.00
BP UK Fatima Limited	Ordinary	100.00
BP UK Retained Holdings Limited	Ordinary	100.00
BP West Aru I Limited	Ordinary	100.00
BP West Aru II Limited	Ordinary	100.00
BP West Papua I Limited	Ordinary	100.00
BP+Amoco International Limited[b]	Ordinary	100.00
Britannic Energy Trading Limited	Ordinary	100.00
Britannic Investments Iraq Limited	Ordinary	100.00
Britannic Marketing Limited	Ordinary	100.00
Britannic Trading Limited	Ordinary	100.00
BTC Pipeline Holding Company Limited	Ordinary	100.00
BXL Plastics Limited	Ordinary; Deferred	100.00
Cadman DBP Limited	Ordinary	100.00
Castrol (U.K.) Limited	Ordinary	100.00
Castrol Holdings Americas Limited	Ordinary	100.00
Castrol Holdings International Limited	Ordinary	100.00
Castrol Offshore Limited	Ordinary	100.00
Exmoor Nominee Limited	Ordinary	51.00
Exmoor Properties GP Limited	Ordinary	51.00
Exmoor Properties PF LP	Membership Interest	51.00
Exploration (Luderitz Basin) Limited	Ordinary	100.00
Fosroc Expandite Limited	Ordinary	100.00
Fotech Group Limited	Ordinary	100.00
GTA FPSO Company Ltd	Ordinary	100.00
Guangdong Investments Limited	Ordinary	100.00
Insight Analytics Solutions Holdings Limited	Ordinary	100.00
Insight Analytics Solutions Limited	Ordinary	100.00
Iraq Petroleum Company Limited	Ordinary	100.00
Kenilworth Oil Company Limited[b]	Ordinary	100.00

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14. Related undertakings of the group – continued

Low Carbon Friends Limited	Ordinary	100.00
Lubricants UK Limited	Ordinary	100.00
Lytt Limited	Ordinary	100.00
Net Zero North Sea Storage Limited	Ordinary	100.00
Net Zero Teesside Power Limited	Ordinary	100.00
Offshore Wind 1 Limited	Ordinary	100.00
Offshore Wind 2 Limited	Ordinary	100.00
Open Energi Limited	Ordinary	100.00
Open Energy Limited	Ordinary	100.00
Pearl River Delta Investments Limited	Ordinary	100.00
Ropemaker Deansgate Limited	Ordinary	100.00
Ropemaker Properties Limited	Ordinary	100.00
Stryde International Limited	Ordinary	100.00
Stryde Limited	Ordinary	100.00
The BP Share Plans Trustees Limited[b]	Ordinary	100.00
Viceroy Investments Limited	Ordinary	100.00
Hutwood Court Bournemouth Road, Chandler's Ford, Eastleigh, Hampshire, SO53 3QB, United Kingdom		
Utilita Group Limited	Ordinary	63.00
Technology Centre, Whitchurch Hill, Pangbourne, Reading, RG8 7QR, United Kingdom		
Castrol Limited	Ordinary	100.00
United States		
1021 Main Street, Suite 1150, Houston, Texas 77002, United States		
BPX Properties (GP) LLC	Membership Interest	100.00
112 SW 7th Street, Suite 3C, Topeka, Kansas, 66603, United States		
Flat Ridge Wind Energy, LLC	Membership Interest	100.00
1209 Orange Street, Wilmington DE 19801, United States		
200 PS Overseas Holdings Inc.	Ordinary	100.00
ACP (Malaysia), Inc.	Ordinary	100.00
AE Cedar Creek Holdings LLC	Membership Interest	100.00
AE Goshen II Holdings LLC	Membership Interest	100.00
AE Goshen II Wind Farm LLC	Membership Interest	100.00
AE Power Services LLC	Membership Interest	100.00
AE Wind PartsCo LLC	Membership Interest	100.00
Air BP Canada LLC	Membership Interest	100.00
AM/PM International Inc.	Ordinary	100.00
American Oil Company	Ordinary	100.00
Amoco (U.K.) Exploration Company, LLC	Membership Interest	100.00
Amoco Capline Pipeline Company	Ordinary	100.00
Amoco Chemical (Europe) S.A.	Ordinary	100.00
Amoco Cypress Pipeline Company	Ordinary	100.00
Amoco Destin Pipeline Company	Ordinary	100.00
Amoco Guatemala Petroleum Company	Ordinary	100.00
Amoco International Finance Corporation	Ordinary	100.00
Amoco International Petroleum Company	Ordinary	100.00
Amoco Louisiana Fractionator Company	Ordinary	100.00
Amoco Main Pass Gathering Company	Ordinary	100.00
Amoco MB Fractionation Company	Ordinary	100.00
Amoco MBF Company	Ordinary	100.00
Amoco Netherlands Petroleum Company	Ordinary	100.00
Amoco Nigeria Petroleum Company	Ordinary	100.00
Amoco Norway Oil Company	Ordinary	100.00
Amoco Olefins Corporation	Ordinary	100.00
Amoco Overseas Exploration Company	Ordinary	100.00
Amoco Pipeline Asset Company	Ordinary	100.00
Amoco Properties Incorporated	Ordinary	100.00
Amoco Remediation Management Services Corporation	Ordinary	100.00
Amoco Research Operating Company	Ordinary	100.00
Amoco Rio Grande Pipeline Company	Ordinary	100.00
Amoco Somalia Petroleum Company	Ordinary	100.00

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14. Related undertakings of the group – continued

Amoco Sulfur Recovery Company	Ordinary	100.00
Amoco Tri-States NGL Pipeline Company	Ordinary	100.00
Amply Power, Inc.	Ordinary	100.00
Amprop, Inc.	Ordinary	100.00
Anaconda Arizona, Inc.	Ordinary	100.00
ARCO British International, Inc.	Ordinary	100.00
ARCO British Limited, LLC	Membership Interest	100.00
ARCO El-Djazair Holdings Inc.	Ordinary	100.00
ARCO Environmental Remediation, L.L.C.	Membership Interest	100.00
ARCO Gaviota Company	Ordinary	100.00
ARCO International Investments Inc.	Ordinary	100.00
ARCO Midcon LLC	Membership Interest	100.00
ARCO Unimar Holdings LLC	Membership Interest	100.00
Atlantic Richfield Company	Ordinary; Preference	100.00
Australia Resource Holdings Inc.	Ordinary	100.00
Auwahi Wind Energy Holdings LLC	Membership Interest	100.00
Black Lake Pipe Line Company	Ordinary	100.00
Blueprint Power Technologies Inc.	Ordinary	100.00
BP Alternative Energy North America Inc.	Ordinary	100.00
BP America Chemicals Company	Ordinary	100.00
BP America Foreign Investments Inc.	Ordinary	100.00
BP America Inc.	Ordinary; Ordinary B	100.00
BP America Production Company	Ordinary	100.00
BP AMI Leasing, Inc.	Ordinary	100.00
BP Amoco Chemical Malaysia Holding Company	Ordinary	100.00
BP Argentina Exploration Company	Ordinary	100.00
BP Argentina Holdings LLC	Membership Interest	100.00
BP Berau Ltd.	Ordinary	100.00
BP Biofuels Advanced Technology Inc.	Ordinary	100.00
BP Biofuels North America LLC	Membership Interest	100.00
BP Bomberai Ltd.	Ordinary	100.00
BP Brazil Tracking L.L.C.	Membership Interest	100.00
BP Canada Energy Marketing Corp.	Membership Interest	100.00
BP Canada Investments Inc.	Ordinary	100.00
BP Capital Markets America Inc.	Ordinary	100.00
BP Carbon Solutions LLC	Membership Interest	100.00
BP Caribbean Company	Ordinary	100.00
BP Central Pipelines LLC	Membership Interest	51.00
BP Chemical Remediation Holdings LLC	Membership Interest	100.00
BP China Exploration and Production Company	Ordinary	100.00
BP Company North America Inc.	Ordinary; Redeemable preference	100.00
BP Containment Response System Holdings LLC	Membership Interest	100.00
BP D-B Pipeline Company LLC	Partnership interest	54.37
BP Egypt Company	Ordinary	100.00
BP Energy Company	Ordinary	100.00
BP Energy Retail LLC	Membership Interest	100.00
BP Exploration & Production Inc.	Ordinary; Preference	100.00
BP Gas Supply (Angola) LLC	Membership Interest	100.00
BP GOM Logistics LLC	Membership Interest	100.00
BP Latin America LLC	Membership Interest	100.00
BP Latin America Upstream Services Inc.	Ordinary	100.00
BP Louisiana Energy Park LLC	Membership Interest	100.00
BP Lubricants USA Inc.	Ordinary	100.00
BP Mariner Holding Company LLC	Membership Interest	100.00
BP Midstream Partners GP LLC	Membership Interest	100.00
BP Midstream Partners Holdings LLC	Membership Interest	100.00
BP Midstream Partners LP	Partnership interest	54.37
BP Midstream RTMS LLC	Membership Interest	100.00

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14. Related undertakings of the group – continued

BP Midwest Product Pipelines Holdings LLC	Membership Interest	51.00
BP Nutrition Inc.	Ordinary	100.00
BP Offshore Gathering Systems Inc.	Ordinary	100.00
BP Offshore Pipelines Company LLC	Membership Interest	100.00
BP Offshore Response Company LLC	Membership Interest	100.00
BP Oil Pipeline Company	Ordinary	100.00
BP Oil Shipping Company, USA	Ordinary	100.00
BP One Pipeline Company LLC	Membership Interest	51.00
BP Pakistan (Badin) Inc.	Ordinary	100.00
BP Pakistan Exploration and Production, Inc.	Ordinary	100.00
BP Pipelines (Alaska) Inc.	Ordinary	100.00
BP River Rouge Pipeline Company LLC	Partnership interest	54.37
BP SC Holdings LLC	Membership Interest	100.00
BP Solar Holding LLC	Membership Interest	100.00
BP Solar International Inc.	Ordinary	100.00
BP Southern Cone Company	Ordinary	100.00
BP Technology Ventures Inc.	Ordinary	100.00
BP Trinidad and Tobago LLC	Membership Interest	70.00
BP Two Pipeline Company LLC	Partnership interest	54.37
BP US Offshore Wind Energy LLC	Membership Interest	100.00
BP Wind Energy Beacon Holding LLC	Membership Interest	100.00
BP Wind Energy Empire Holding LLC	Membership Interest	100.00
BP Wind Energy North America Inc.	Ordinary	100.00
BP Wiriagar Ltd.	Ordinary	100.00
BPX (Eagle Ford) Gathering LLC	Membership Interest	75.00
BPX (Karnes) Gathering LLC	Membership Interest	100.00
BPX (KCS Resources) LLC	Membership Interest	100.00
BPX (Permian) Gathering LLC	Membership Interest	100.00
BPX Energy Inc.	Ordinary	100.00
BPX Gathering Holdings LLC	Membership Interest	100.00
BPX Production Company	Ordinary	100.00
BPX Properties (LP) LLC	Membership Interest	100.00
Burmah Castrol Holdings Inc.	Ordinary	100.00
Casitas Pipeline Company	Ordinary	100.00
Castrol Caribbean & Central America Inc.	Ordinary	100.00
CH-Twenty, Inc.	Ordinary	100.00
Coastwise Trading Company, Inc.	Ordinary	100.00
Cuyama Pipeline Company	Ordinary	100.00
Elm Holdings Inc.	Ordinary	100.00
Energy Global Investments (USA) Inc.	Ordinary	100.00
Enstar LLC	Membership Interest	100.00
Flat Ridge 2 Holdings LLC	Membership Interest	100.00
Foseco Holding, Inc.	Membership Interest	100.00
Foseco, Inc.	Ordinary	100.00
Fowler I Holdings LLC	Membership Interest	100.00
Fowler Ridge Holdings LLC	Membership Interest	100.00
Fowler Ridge I Land Investments LLC	Membership Interest	100.00
Fowler Ridge II Holdings LLC	Membership Interest	100.00
Fowler Ridge III Wind Farm LLC	Membership Interest	100.00
Gardena Holdings Inc.	Ordinary	100.00
Highlands Ethanol, LLC	Membership Interest	100.00
Ken-Chas Reserve Company	Ordinary	100.00
Mardi Gras Transportation System Company LLC	Membership Interest	70.34
Mehoopany Holdings LLC	Membership Interest	100.00
Mountain City Remediation, LLC	Membership Interest	100.00
North America Funding Company	Ordinary	100.00
Orion Delaware Mountain Wind Farm LP	Membership Interest	100.00
Orion Energy Holdings, LLC	Membership Interest	100.00
Orion Energy L.L.C.	Membership Interest	100.00

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14. Related undertakings of the group – continued

Pan American Energy US LLC	Membership Interest	51.00
Remediation Management Services Company	Ordinary	100.00
Richfield Oil Corporation	Ordinary	100.00
Rolling Thunder I Power Partners, LLC	Membership Interest	100.00
Sherbino I Holdings LLC	Membership Interest	100.00
Sherbino Mesa I Land Investments LLC	Membership Interest	100.00
South Texas Shale LLC	Membership Interest	100.00
Southern Ridge Pipeline Holding Company	Ordinary	100.00
Southern Ridge Pipeline LP LLC	Membership Interest	100.00
Stryde Inc.	Ordinary	100.00
Thorntons LLC	Membership Interest	100.00
TLK Holding Company LLC	Membership Interest	100.00
TLK Intermediate Holding Company LLC	Membership Interest	100.00
TLK Operating Company LLC	Membership Interest	100.00
Toledo Refinery Holding Company LLC	Membership Interest	100.00
Union Texas International Corporation	Ordinary	100.00
Vastar Pipeline, LLC	Membership Interest	100.00
Westlake Houston Development, LLC	Membership Interest	100.00
Whiting Clean Energy, Inc.	Membership Interest	100.00
150 West Market Street, Suite 800, Indianapolis IN 46204, United States		
BP Corporation North America Inc.	Ordinary	100.00
1833 South Morgan Road, Oklahoma City OK 73128, United States		
BPX Midstream LLC	Membership Interest	100.00
1999 Bryan St., STE 900, Dallas, TX, 75201, United States		
Acamar Energy Project, LLC	Membership Interest	100.00
Andromedae Energy Project, LLC	Membership Interest	100.00
Arche Energy Project, LLC	Membership Interest	100.00
Atria Energy Project, LLC	Membership Interest	100.00
Bellatrix Energy Project, LLC	Membership Interest	100.00
BP Solar SHH, LLC	Membership Interest	100.00
BP Solar SHP, LLC	Membership Interest	100.00
BPX Operating Company	Ordinary	100.00
BPX Properties (NA) LP	Partnership interest	100.00
Buzz Energy Project, LLC	Membership Interest	100.00
Cassiopeia Energy Project, LLC	Membership Interest	100.00
Cepheus Energy Project, LLC	Membership Interest	100.00
Cressida Energy Project, LLC	Membership Interest	100.00
Delphinus Energy Project, LLC	Membership Interest	100.00
Despina Energy Project, LLC	Membership Interest	100.00
Draconis Energy Project, LLC	Membership Interest	100.00
Elanor Energy Project, LLC	Membership Interest	100.00
Electra Energy Project, LLC	Membership Interest	100.00
Fotech USA, LLC	Membership Interest	100.00
Juliet Energy Project, LLC	Membership Interest	100.00
Maia Energy Project, LLC	Membership Interest	100.00
Minkar Energy Project, LLC	Membership Interest	100.00
Mira Energy Project, LLC	Membership Interest	100.00
Nashira Energy Project, LLC	Membership Interest	100.00
Nunki Energy Project LLC	Membership Interest	100.00
Peacock Energy Project, LLC	Membership Interest	100.00
Perdita Energy Project, LLC	Membership Interest	100.00
Persei Energy Project, LLC	Membership Interest	100.00
Rigel Energy Project, LLC	Membership Interest	100.00
Shaula Energy Project II, LLC	Membership Interest	100.00
Shaula Energy Project III, LLC	Membership Interest	100.00
Shaula Energy Project, LLC	Membership Interest	100.00
Spica Energy Project, LLC	Membership Interest	100.00
Subra Energy Project, LLC	Membership Interest	100.00
Taika Energy Project, LLC	Membership Interest	100.00

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14. Related undertakings of the group – continued

Tania Energy Project, LLC	Membership Interest	100.00
Telesto Energy Project, LLC	Membership Interest	100.00
Tesni Energy Project, LLC	Membership Interest	100.00
Thalassa Energy Project, LLC	Membership Interest	100.00
Venatici Energy Project, LLC	Membership Interest	100.00
Zibal Energy Project, LLC	Membership Interest	100.00
208 South LaSalle Street, Suite 814, Chicago, IL, 60604-1101, United States		
Amprop Illinois I Limited Partnership	Partnership interest	100.00
Dradnats, Inc.	Ordinary	100.00
2108 55th Street, Suite 105, Boulder CO 80301, United States		
Insight Analytics Solutions USA, Inc	Ordinary	100.00
2405 York Road, Ste 201, Lutherville Timonium, MD, 21093-2264, United States		
BP Products North America Inc.	Ordinary	100.00
251 East Ohio Street, Suite 500, Indianapolis IN 46204, United States		
AmProp Finance Company	Ordinary	100.00
BP Foundation Incorporated	Membership Interest	100.00
Standard Oil Company, Inc.	Ordinary	100.00
2711 Centerville Road, Suite 400, Wilmington DE 19808, United States		
Amoco Oil Holding Company	Ordinary	100.00
Amoco Pipeline Holding Company	Ordinary	100.00
BP International Services Company	Ordinary	100.00
Finite Resources, Inc.	Ordinary	80.50
Orion Post Land Investments, LLC	Membership Interest	100.00
Welchem, Inc.	Ordinary	100.00
306 W. Main Street, Suite 512, Frankfort, KY, 40601, United States		
Fresh-Serve Bakeries LLC	Membership Interest	100.00
Thornton Transportation LLC	Membership Interest	100.00
33 North LaSalle Street, Chicago, Illinois 60602, United States		
Warrenville Development Limited Partnership	Membership Interest	100.00
3800 North Central Avenue, Suite 460, Phoenix, AZ, 85012, United States		
Sargas Energy Project, LLC	Membership Interest	100.00
400 Cornerstone Drive, Suite 240, Williston VT 05495, United States		
Saturn Insurance Inc.	Ordinary	100.00
435 Devon Park Drive, Suite 700, Wayne, Pennsylvania, 19087, United States		
Finite Carbon Corporation	Ordinary	80.50
4400 Easton Commons Way , Suite 125, Columbus OH 43219, United States		
Baltimore Ennis Land Company, Inc.	Ordinary	100.00
Exomet, Inc.	Ordinary	100.00
The Standard Oil Company	Ordinary	100.00
45 Memorial Circle, Augusta ME 04330, United States		
BP Pipelines (North America) Inc.	Ordinary	100.00
5615 Corporate Blvd., Suite 400B, LA 70808, Baton Rouge, United States		
BPX (WSF Operating) Inc.	Ordinary	100.00
Winwell Resources, L.L.C.	Membership Interest	100.00
701 South Carson Street Suite 200, Carson City, NV, 89701, United States		
Amoco Marketing Environmental Services Company	Ordinary	100.00
814 Thayer Avenue, Bismarck, ND, 58501-4018, United States		
The Anaconda Company	Ordinary	100.00
920 North King Street, 2nd Floor, Wilmington DE 19801, United States		
BPRY Caribbean Ventures LLC	Membership Interest	70.00
921 S. Orchard St. Ste G, Boise ID 83705, United States		
IGI Resources, Inc.	Ordinary	100.00
Bank of America Center, 16th Floor, 1111 East Main Street, Richmond VA 23219, United States		
Amoco Environmental Services Company	Ordinary; Preference	100.00
1021 Main Street, Suite 1150, Houston, Texas 77002, United States		
BPX Properties (GP) LLC	Membership Interest	100.00

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14. Related undertakings of the group – continued

Venezuela		
Av. Francisco de Miranda, con primera avenida de Los Palos, Grandes, Edif Cavendes, piso 9, ofi 903, Los Palos Grandes, Caracas / Miranda, Chacao / Caracas, 1060, Venezuela		
BP Exploracion de Venezuela S.A.	Ordinary	100.00
BP Petroleo y Gas, S.A.	Ordinary	100.00
Avenida Eugenio Mendoza / San Felipe Edificio Centro Letonia, Torre Ing-Bank, Piso 12, Oficina 124-B, La Castellana, Caracas, 1060, Venezuela		
Consolidada de Energia y Lubricantes, (CENERLUB) C.A.	Ordinary	100.00
Prospect International, C.A. (In liquidation)	Ordinary	100.00
Vietnam		
9th Floor, 22-36 Nguyen Hue Street, 57-69F Dong Khoi Street, District 1, Ho Chi Minh City, Vietnam		
Castrol BP Petco Limited Liability Company	Membership Interest	65.00
Zimbabwe		
Barking Road, Willowvale, Harare, Zimbabwe		
Castrol Zimbabwe (Private) Limited	Membership Interest	100.00

Related undertakings other than subsidiaries

Company by country and address of incorporation	Ownership interest	%
Argentina		
Av. Leandro N. Alem 1180, piso 11°, Buenos Aires, Argentina		
Field Services Enterprise S.A.	Ordinary	50.00
Parque Eolico Del Sur S.A.	Ordinary	27.50
Terminal CP S.A.U.	Ordinary	50.00
Vientos Ombu III S.A.	Ordinary	25.00
Calle 14, No 781, Piso 2, Oficina 3, Ciudad de La Plata, Provincia de Buenos Aires, Argentina		
Barranca Sur Minera S.A.	Ordinary	50.00
Carlos María Della Paolera 265, Piso 22, Ciudad Autónoma de Buenos Aires, Argentina		
Axion Energy Argentina S.A.	Ordinary	50.00
Florida 1, Piso 10, Buenos Aires, Argentina		
Oleoductos del Valle (Oldelval) S.A.	Ordinary	50.00
Francisco Behr 20, Barrio Pueyrredon, Comodoro Rivadavia, Provincia del Chubut, Argentina		
Manpetrol S.A.	Ordinary	50.00
Lavalle 190, piso 6 Depto L, Buenos Aires, Argentina		
Vientos Patagonicos Chubut Norte III S.A.	Ordinary	24.50
Vientos Sudamericanos Chubut Norte IV S.A.	Ordinary	24.50
O´Higgins N° 194, Rio Grande, Argentina		
Pan American Fueguina S.A.	Ordinary	50.00
Pan American Sur S.A.	Ordinary	50.00
San Martin 140, Piso 2, Buenos Aires, Argentina		
Central Dock Sud S.A.	Ordinary	50.00
Australia		
11 Lagoon Court, Samford Valley, QLD 4520, Australia		
Australasian Lubricants Manufacturing Company Pty Ltd	Ordinary A	50.00
CBW Level 19, 181 William Street, Melbourne VIC 3000, Australia		
3725 Sharp Development Pty Ltd	Ordinary	49.97
433 Link Development Company Pty Ltd	Ordinary	49.97
892 Yarrawonga Development Pty Ltd	Ordinary	49.97
Lightsource Asset Management Australia Pty Ltd	Ordinary	49.97
Lightsource Australia SPV 1 Pty Limited	Ordinary	49.97
Lightsource Australia SPV 2 Pty Ltd	Ordinary	49.97
Lightsource Australia SPV 3 Pty Ltd	Ordinary	49.97
Lightsource Australia SPV 4 Pty Ltd	Ordinary	49.97
Lightsource Development Services Australia Pty Ltd	Ordinary	49.97
Lightsource Energy Markets Pty Ltd	Ordinary	49.97
Lightsource LS Labs Australia Operations Pty Ltd	Ordinary	49.97
Lightsource Labs Australia Pty Limited	Ordinary	49.97
Lightsource Renewable Energy (Australia) Pty Ltd	Ordinary	49.97
LS Australia Equity HoldCo1 Pty Ltd	Ordinary	49.97

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14. Related undertakings of the group – continued

LS Australia FinCo 1 Pty Ltd	Ordinary	49.97
LS Australia FinCo 2 Pty Ltd	Ordinary	49.97
LS Australia HoldCo 1 Pty Ltd	Ordinary	49.97
Sun Spot 3 Pty Ltd	Ordinary	49.97
Wellington LandCo Pty Ltd	Ordinary	49.97
Wellington North Solar Farm Pty Ltd	Ordinary	49.97
West Mokoan Solar Farm Pty Ltd	Ordinary	49.97
West Wyalong FinCo Pty Ltd	Ordinary	49.97
West Wyalong Fund Pty Ltd	Ordinary	49.97
West Wyalong HoldCo 2 Pty Ltd	Ordinary	49.97
West Wyalong Trust	Membership Interest	49.97
Woolooga FinCo Pty Ltd	Ordinary	49.97
Woolooga Fund Pty Ltd	Ordinary	49.97
Woolooga HoldCo 2 Pty Ltd	Ordinary	49.97
Woolooga Trust	Membership Interest	49.97
Wunghnu Solar Farm FinCo Pty Ltd	Ordinary	49.97
Wunghnu Solar Farm HoldCo Pty Ltd	Ordinary	49.97
Company Matters Pty Ltd, Level 12, 680 George Street, Sydney NSW 2000, Australia		
Airport Fuel Services Pty. Limited	Ordinary	20.00
Cairns Airport Refuelling Service Pty Ltd	Ordinary	33.33
Level 10, 12 Creek Street, Brisbane, QLD 4000, Australia		
Ocwen Energy Pty Ltd	Ordinary	49.50
Level 3, Unit 3, 22 Albert Road, South Melbourne VIC 3205, Australia		
Australian Terminal Operations Management Pty Ltd	Ordinary	50.00
Austria		
Am Tankhafen 4, 4020 Linz, Austria		
TLM Tanklager Management GmbH	Membership Interest	49.00
Brucknerstraße 4, 1041 Wien, Austria		
ABG Autobahn-Betriebe GmbH	Membership Interest	32.58
Innsbrucker Bundesstraße 95, 5020 Salzburg, Austria		
Salzburg Fuelling GmbH	Membership Interest	33.00
Radlpaßstraße 6, 8502 Lannach, Austria		
Erdol-Lagergesellschaft m.b.H.	Membership Interest	23.00
Trabrennstraße 6-8 3, A-1020, Wien, Austria		
Aircraft Refuelling Company GmbH	Membership Interest	33.33
Bahamas		
Trinity Place Annex, Corner of Frederick & Shirley Streets, P.O. Box N-4805, Nassau, Bahamas		
PAE E & P Bolivia Limited	Ordinary	50.00
Pan American Energy Investments Ltd.	Ordinary	50.00
Bolivia		
Av San Martin 1700, Cuarto Anillo, Edificio Centro Empresarial Equipetrol, Piso 6, Zona Oeste, Equipetrol Norte, Santa Cruz de la Sierra, Bolivia		
YPFB Chaco S.A.	Ordinary	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		
PAE Oil & Gas Bolivia Ltda.	Ordinary	50.00
Brazil		
1675 South State Street, Suite B, Dover, Kent Country, DE, 19901 US, Brazil		
Pan American Energy Energias Renovaveis Ltda.	Ordinary	50.00
Al Santos, 74, Andar 7 Conj 72 Sala 53, Cerqueira Cesar, Sao Paulo, 01.418-000, Brazil		
Lightsource Milagres Holding 1 S.A.	Ordinary	49.97
Av. Bernardino de Campos, n. 98., Conj. A, 12 Andar, Sala 37, Paraiso, São Paulo, 04.004-040, Brazil		
Lightsource Brasil Energia Renovável Participções S.A.	Ordinary	49.97
Avenida Anita Garibaldi, 252, 2nd floor, Ala Sul, Federação, city of Salvador, State of Bahia, 40.210-750, Brazil		
Air BP Petrobahia Ltda.	Ordinary	50.00
Avenida Atlântica, no. 1.130, 2nd floor (part), Copacabana,RJ, Rio de Janeiro, 22021-000, Brazil		
NFX Combustíveis Marítimos Ltda.	Ordinary	50.00
Avenida Bernardino de Campos 98, 12th floor, room 38, suite A, Paraiso, Sao Paulo, 04004-040, Brazil		
Lightsource Brasil Energia Renovável Ltda	Ordinary	49.97

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14. Related undertakings of the group – continued

Avenida das Nações Unidas, 12.399, 4º andar, cj. 41B, sala 01, São Paulo, Brazil		
BP Biofuels Trading Comércio, Importação e Exportação Ltda.	Ordinary	48.27
Avenida das Nações Unidas, nº 12.399, 4º andar, Brooklin Paulista, São Paulo, CEP 04578-000, Brazil		
BP Bunge Bioenergia S.A.	Ordinary	48.27
Avenida Paris, 4077, Suite 3, Cascata,São Paulo State, Paulínia, 13046-061, Brazil		
Terminal de Combustiveis Paulinia S.A.	Ordinary	50.00
Estrada BR 135, número S/N, KM 250, bairro / distrito Angico de Minas, município Japonvar - MG, CEP 39335-000, Brazil		
Porteiras Geração de Energia Ltda.	Ordinary	49.97
Estrada Caraúbas sentido ao distrito de Mirandas, S/N, Km 15, lado esquerdo, Zona Rural, Sitio Retiro, Município de Caraúbas/RN, CEP 59780-000, Brazil		
Lightsource Caraúbas Geração de Energia Ltda	Ordinary	49.97
Estrada de São Romão, KM23, S/N, Zona Rural, Fazenda São Francisco, Buritizeiro/MG, CEP 39280-000, Brazil		
Lightsource Andorinhas Geração de Energia Ltda.	Ordinary	49.97
Estrada Mossoró sentido Jaguaruana, S/N, Km 48, lado esquerdo, Zona Rural, Sitio Aroeira Grande, Município de Baraúna/RN, CEP 59695-000, Brazil		
Lightsource Jaguar Geração de Energia Ltda	Ordinary	49.97
Estrada Municipal Itumbiara / Chacoeira Dourada, Fazenda Jandaia, Gleba B, Goiás, Itumbiara, 75516-126, Brazil		
BP Bioenergia Itumbiara S.A.	Ordinary	48.27
Estrada que liga Brejo Santo a Vila Conceição, porteira da Caatinga Grande, S/N, Zona Rural, Sitio Ludovico, Município de Brejo Santo/CE, CEP 63260-000, Brazil		
Lightsource Milagres Expansão Geração de Energia Ltda	Ordinary	49.97
Fazenda Água Amarela, S/N, Itapegipe, Minas Gerais, 38240-000, Brazil		
Itapagipe Bioenergia Ltda.	Ordinary	48.27
Fazenda Guariroba, SN, Zona Rural, Pontes Gestal, São Paulo, 15500-000, Brazil		
Usina Guariroba Ltda.	Ordinary	48.27
Fazenda Moema, s/n, Rural, Orindiuva, São Paulo, 15480-000, Brazil		
Bunge Açúcar e Bioenergia S.A.	Ordinary	48.27
Fazenda Recanto, Zona Rural, CEP 38.300-898, Minas Gerais, Ituiutaba, Brazil		
BP Bioenergia Ituiutaba Ltda.	Ordinary	48.27
Fazenda Santa Bárbara, S/N, Distrito de Zelândia, Santa Juliana, Minas Gerais, 38175-000, Brazil		
Santa Juliana Bioenergia Ltda.	Ordinary	48.27
Fazenda São Bento da Ressaca, S/N, Zona Rural, Frutal, Minas Gerais, 38200-000, Brazil		
Frutal Bioenergia Ltda.	Ordinary	48.27
Fazenda Terra Nova, located at Rod. Padre Cicero (CE 153), S/N, KM 58, Lima Campos, Ceara, Ico, 63.435-000, Brazil		
Lightsource Bom Lugar IV Geração de Energia Ltda	Ordinary	49.97
Lightsource Bom Lugar IX Geração de Energia Ltda.	Ordinary	49.97
Lightsource Bom Lugar V Geração de Energia Ltda.	Ordinary	49.97
Lightsource Bom Lugar VI Geração de Energia Ltda.	Ordinary	49.97
Lightsource Bom Lugar VII Geração de Energia Ltda.	Ordinary	49.97
Lightsource Bom Lugar VIII Geração de Energia Ltda.	Ordinary	49.97
Fazenda Vista Alegre I, KM 25, S/N, Zona Rural, Jaíba/ MG, CEP 39508-000, Brazil		
Lightsource Pomar do Sertão Geração de Energia Ltda.	Ordinary	49.97
Praia do Flamengo 66, 13th and 14th floors, Block A, Flamengo, Rio de Janeiro, Brazil		
Gas Natural Acu S.A.	Ordinary	30.00
Rodovia GO 410, km 51 à esquerda, Fazenda Canadá, s/n, Zona Rural, Goiás, Edéia, 75940-000, Brazil		
BP Bioenergia Tropical S.A.	Ordinary	48.27
Rodovia Iaciara sentido Alvorada, Margem Direita, S/N, Zona Rural, Fazenda Ferradura e Campo Aberto, Município de Posse/GO, CEP 73900-000, Brazil		
Lightsource Guara Geracao de Energia Ltda	Ordinary	49.97
Rodovia SP - 463 Elyeser Montenegro Magalhãe, KM 186, S/N, Zona Rural,São Paulo, Ouroeste, 15685-000, Brazil		
Usina Ouroeste - Açúcar e Álcool Ltda.	Ordinary	48.27
Rodovia TO 010 KM 20, S/N, Zona Rural, Cidade de Pedro Afonso, Tocantins, 77710-000, Brazil		
Pedro Afonso Bioenergia Ltda.	Ordinary	48.27
Rua do Russel 804, 5th floor, Gloria, Rio de Janeiro, Brazil		
Gas Natural Acu Comercializadora de Energia Ltda.	Ordinary	50.00
Gas Natural Infraestrutura S.A.	Ordinary	27.91
Rua Manoel da Nóbrega nº1280, 10º andar, Sao Paulo, Sao Paulo, 04001-902, Brazil		
Pan American Energy do Brasil Ltda.	Membership Interest	50.00
Rua Principal, Fazenda Recanto, Zona Rural, Caixa Postal 01, Minas Gerais, Ituiutaba, 38.300-898, Brazil		
BP Bioenergia Campina Verde Ltda.	Ordinary	48.27

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14. Related undertakings of the group – continued

Sítio Cajueiro - Abaiara - left of BR 116, KM491, Caatinga Grande, Zona Rural, Abaiara, 63.240-000, Brazil		
Lightsource Milagres I Geração de Energia S.A	Ordinary	49.97
Lightsource Milagres II Geração de Energia S.A	Ordinary	49.97
Lightsource Milagres III Geração de Energia S.A	Ordinary	49.97
Lightsource Milagres IV Geração de Energia S.A	Ordinary	49.97
Lightsource Milagres V Geração de Energia S.A	Ordinary	49.97
Sítio Paus Pretos, S/N, BR 316, Rood Floresta/Petrolandia, Km 314, Floresta/PE, Zip Code 56.4000-000, Brazil		
Lightsource Flor Geração de Energia Ltda.	Ordinary	49.97
Canada		
c/o Husky Oil Operations Limited, 707 - 8th Avenue SW, Calgary AB T2P 1H5, Canada		
Sunrise Oil Sands Partnership	Partnership interest	50.00
Cayman Islands		
190 Elgin Avenue, George Town, KY1-9005, Cayman Islands		
Azerbaijan International Operating Company	Unlimited redeemable	30.37
Georgian Pipeline Company	Unlimited redeemable	30.37
P.O. Box 309, Ugland House, 113 South Church Street, George Town, Cayman Islands		
Azerbaijan Gas Supply Company Limited	Ordinary A	23.06
BTC International Investment Co.	Membership Interest	30.10
South Caucasus Pipeline Company Limited	Membership Interest	28.83
South Caucasus Pipeline Holding Company Limited	Membership Interest	28.83
South Caucasus Pipeline Option Gas Company Limited	Ordinary	28.83
The Baku-Tbilisi-Ceyhan Pipeline Company	Membership Interest	30.10
Chile		
Nueva de Lyon Nº 145, piso 12, oficina 1203, Edificio Costa, Santiago de Chile, Chile		
Pan American Energy Chile Limitada	Ordinary	50.00
China		
10-11/FTime Finance Center, No.4001 Shennan Dadao, Futian Street, Futian District,Guangdong Province, Shenzhen, China		
Guangdong Dapeng LNG Company Limited	Membership Interest	30.00
11/F, Building No.2, No. 32 Lingang Road Section One, Xihang Port Street, Shuangliu District,Sichuan Province, Chengdu, China		
CNAF Air BP General Aviation Fuel Company Limited	Membership Interest	49.00
2-5F, No. 571, Yuncheng Dong Road, Baiyun District, Guangdong Province, Guangzhou City, China		
South China Bluesky Aviation Oil Company Limited	Membership Interest	24.50
5th Floor, Guangsha Ruiming Building, No. 231 Moganshan Road, Xihu District, Hangzhou, Zhejiang Province, China		
BP Sinopec (ZheJiang) Petroleum Co., Ltd	Membership Interest	40.00
Fu Yong Town, Bao An county, Guangdong Province, ShenZhen Airport, China		
Shenzhen Cheng Yuan Aviation Oil Company Limited	Membership Interest	25.00
Guangdong Dapeng Liquefied Natural Gas Filling Station, Cheng Tou Corner, Xia Sha Village, Dapeng Street, Dapeng New District, Shenzhen, China		
Shenzhen Dapeng LNG Marketing Company Limited	Membership Interest	30.00
Nanweitong Village Oil Station, Dongerhuan Road, Yuhua District, Shijiazhuang, Hebei Province, China		
Hebei Dongming Yinglun Petroleum Co., Ltd.	Membership Interest	49.00
No. B933, 9-14/F Office, Building A, Baoye Center, NO.31 JIA, China		
Castrol DongFeng Lubricant Co., Ltd	Membership Interest	50.00
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, Zhenzh, China		
Henan Dongming Yinglun Petroleum Co., Ltd.	Membership Interest	49.00
Room 3501, Room 3502, Room 3503, No.62, Jinsui Road, Tianhe District, Guangzhou, China		
Guangzhou Aulton New Energy Technology Co., Ltd.	Membership Interest	20.00
Room 526, No.13,Longxue Avenue middle, Nansha District, Guangzhou, China		
BP Guangzhou Development Oil Product Co., Ltd	Membership Interest	40.00
Room 8309, Floor 3, Yufanghailian Office Building, No. 1 Indian Ocean Road, West Coast Comprehensive Bonded Area, Qingdao Division of the PRC China		
BP SPG Energy Trading Co., Ltd.	Membership Interest	49.00
Room A, building B, 5th floor, no. 22 Gangkou road, Jiangmen, China		
BP Petro China Jiangmen Fuels Co., Ltd.	Membership Interest	49.00
Room B1, 11th Floor, No.22 Gang Kou Yi Road, Peng Jiang District,Guangdong Province, Jiangmen, China		
BP PetroChina Petroleum Co., Ltd	Membership Interest	49.00

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14. Related undertakings of the group – continued

Room B-703, B-704, B-705, B-706, B-707, Floor 7, Block B, No.8, Luoyuan Avenue, Lixia District, Jinan City, China		
Shandong Dongming Yinglun Petroleum Co., Ltd.	Membership Interest	49.00
Cuba		
Calle 6 No 319, esq 5ta. Ave., Miramar, Playa, La Habana, Cuba		
Castrol Cuba S.A.	Ordinary	50.00
Cyprus		
90 Archiepiskopou str, Dromolaxia – Meneou, 7020 Larnaca, Cyprus		
LCA Aviation Fuelling Systems Limited	Ordinary	35.00
Denmark		
GA Centervej 1, Billund, DK-7190, Denmark		
Billund Refuelling I/S	Membership Interest	50.00
Kastrup Lufthavn, 2770 Kastrup, Denmark		
Danish Refuelling Services I/S	Partnership interest	50.00
Danish Tankage Services I/S	Partnership interest	50.00
Københavns, Lufthavn, 2770 Kastrup, Denmark		
Braendstoflageret Kobenhavns Lufthavn I/S	Partnership interest	20.83
Egypt		
14 Kamal El Tawil ST, Zamalek, Cairo, Egypt		
Lightsource BP Hassan Allam Developments for Renewable Energy S.A.E	Ordinary	24.99
5 El Mokhayam El Daiem St, 6th Sector, Nasr City, Egypt		
El Temsah Petroleum Company "PETROTEMSAH"	Ordinary	25.00
Mediteranean Gas Co. "MEDGAS"	Ordinary	25.00
70/72 Road 200, Maadi, Cairo, Egypt		
Pharaonic Petroleum Company "PhPC"	Ordinary	25.00
Rahamat Petroleum Company (PETRORAHAMAT)	Ordinary	50.00
85 El Nasr Road, Cairo, Egypt		
Natural Gas Vehicles Company "NGVC"	Ordinary	40.00
Building No. 349 & 351, Third Sector of City Centre, Fifth Settlement, New Cairo, Egypt		
United Gas Derivatives Company "UGDC"	Ordinary	33.33
Street 200, Building 70-72, Maadi, Cairo, Egypt		
Damietta Petroleum Company "PETRODAMIETTA"	Ordinary	50.00
North El Burg Petroleum Company "PETRONEB"	Ordinary	25.00
France		
1 Place Gustave Eiffel, Rungis, 94150, France		
Société d'Avitaillement et de Stockage de Carburants Aviation "SASCA"	Membership Interest	40.00
150 Avenue Yves Farge, Saint Pierre des Corps, 37700, France		
Depot Petrolier De Saint-Pierre Des Corps D.P.S.P.C.	Membership Interest	20.00
27 Route du Bassin Numéro 6, Gennevilliers, 92230, France		
Société de Gestion de Produits Pétroliers - SOGEPP	Ordinary	37.00
3 Rue des Vignes, Aéroport Roissy Charles de Gaulle, Tremblay en France, 93290, France		
Fuelling Aviation Service - FAS	Membership Interest	50.00
562 Avenue du Parc de l'Ile, Nanterre, 92000, France		
Entrepot petrolier de Chambery	Ordinary	32.00
9 Rue Boissy d'Anglas, 75008 Paris, France		
Lightsource France Development SAS	Ordinary	49.97
Germany		
Am Stadthafen 60, 45881 Gelsenkirchen, Germany		
TransTank GmbH	Ordinary	50.00
An der Braker Bahn 22, 26122 Oldenburg, Germany		
Klaus Köhn GmbH	Ordinary	50.00
Köhn & Plambeck GmbH & Co. KG	Partnership interest	50.00
Berghausener Straße 96, 40764 Langenfeld, Germany		
AGES International GmbH & Co. KG, Langenfeld	Partnership interest	24.70
AGES Maut System GmbH & Co. KG, Langenfeld	Partnership interest	24.70
Bertrand-Russell-Straße 3, 22761 Hamburg, Germany		
Etzel-Kavernenbetriebsgesellschaft mbH & Co. KG	Partnership interest	33.33
Etzel-Kavernenbetriebs-Verwaltungsgesellschaft mbH	Ordinary	33.33
Brunnenstraße 19-21, Berlin, 10119, Germany		
Digital Charging Solutions GmbH	Membership Interest	33.33

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14. Related undertakings of the group – continued

Godorfer Hauptstraße 186, 50997 Köln, Germany		
Rhein-Main-Rohrleitungstransportgesellschaft mbH	Ordinary	35.00
Huestraße 25, Bochum, 44787, Germany		
TRaBP GbR	Partnership interest	75.00
Jenfelder Allee 80, Hamburg, 22039, Germany		
STDG Strassentransport Dispositions Gesellschaft mbH	Ordinary	50.00
Luisenstraße 5 a, 26382 Wilhelmshaven, Germany		
Ammenn GmbH	Ordinary	75.00
Kurt Ammenn GmbH & Co. KG	Partnership interest	50.00
Raffineriestraße 1, Lingen, 49808, Germany		
Lingen Green Hydrogen Management GmbH	Ordinary	50.00
Rheinstraße 36, 49090 Osnabrück, Germany		
Fip Verwaltungs GmbH	Ordinary	50.00
Heinrich Fip GmbH & Co. KG	Partnership interest	50.00
Saganer Straße 31, 90475 Nürnberg, Germany		
Beer Energien GmbH & Co. KG	Partnership interest	50.00
Beer GmbH	Ordinary	50.00
Spaldingstraße 64, 20097 Hamburg, Germany		
Mobene Beteiligungs GmbH & Co. KG	Partnership interest	50.00
Mobene Beteiligungs Verwaltungs GmbH	Ordinary	50.00
Mobene GmbH & Co. KG	Partnership interest	50.00
Mobene Verwaltungs-GmbH	Ordinary	50.00
Sportallee 6, 22335 Hamburg, Germany		
Dusseldorf Fuelling Services GbR	Partnership interest	33.00
Hamburg Tank Service (HTS) GbR	Partnership interest	33.00
HFS Hamburg Fuelling Services GbR	Partnership interest	50.00
LFS Langenhagen Fuelling Services GbR	Partnership interest	50.00
TFSS Turbo Fuel Services Sachsen GbR	Partnership interest	20.00
TGH Tankdienst-Gesellschaft Hamburg GbR	Partnership interest	66.67
TGHL Tanklager-Gesellschaft Hannover-Langenhagen GbR	Partnership interest	50.00
TGK Tanklagergesellschaft Koln-Bonn	Partnership interest	25.00
Steindamm 55, 20099 Hamburg, Germany		
GVÖ Gebinde-Verwertungsgesellschaft der Mineralölwirtschaft mbH	Ordinary	21.00
Überseeallee 1, 20457, Hamburg, Germany		
Flughafen Hannover Pipeline Verwaltungsgesellschaft mbH	Ordinary	50.00
Flughafen Hannover Pipelinegesellschaft mbH & Co. KG	Partnership interest	50.00
Lingen Green Hydrogen GmbH & Co. KG	Ordinary	50.00
Wesermünder Straße 1, 27729 Hambergen, Germany		
Tecklenburg GmbH	Ordinary	50.00
Tecklenburg GmbH & Co. Energiebedarf KG	Partnership interest	50.00
Westfalendamm 166, 44141 Dortmund, Germany		
DOPARK GmbH	Ordinary	25.00
Wittener Straße 45, 44789 Bochum, Germany		
CSG Convenience Service GmbH	Ordinary	24.80
Trafineo Service GmbH	Ordinary	75.00
Wittener Straße 56, Bochum, Germany		
Trafineo GmbH & Co. KG	Partnership interest	75.00
Trafineo Verwaltungs-GmbH	Ordinary	75.00
Zum Ölhafen 49, 70327 Stuttgart, Germany		
TLS Tanklager Stuttgart GmbH	Ordinary	45.00
Ghana		
Number 1, Rehoboth Place, Dade Street, North Labone Estates, Accra, Greater Accra, Accra Metropolitan, P. O. BOX CT327, Ghana		
BP West Africa Supply Limited	Ordinary	50.00
Greece		
2,Vouliagmenis Ave & Papaflessa, 16777 Elliniko, Attika, Athens, Greece		
GISSCO S.A.	Ordinary	50.00
280 Kifisias Avenue, 15232 Chalandri, Greece		
Lightsource Renewable Energy Greece Development Single Member S.A.	Ordinary	49.97

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14. Related undertakings of the group – continued

Lightsource Renewable Energy Greece Projects Single Member S.A.	Ordinary	49.97
Anonymous Municipal Road 051100, Kyrakali, Grevena, Greece		
Clean Energy 1 S.M.S.A.	Ordinary	49.97
Clean Energy 2 S.M.S.A.	Ordinary	49.97
Clean Energy 3 S.M.S.A.	Ordinary	49.97
Clean Energy 4 S.M.S.A.	Ordinary	49.97
Clean Energy 5 S.M.S.A.	Ordinary	49.97
Clean Energy 6 S.M.S.A.	Ordinary	49.97
Green Energy Plus 1 S.M.S.A.	Ordinary	49.97
Green Energy Plus 2 S.M.S.A.	Ordinary	49.97
Green Energy Plus 3 S.M.S.A.	Ordinary	49.97
Green Energy Plus 4 S.M.S.A.	Ordinary	49.97
Green Energy Plus 5 S.M.S.A.	Ordinary	49.97
Green Energy Plus 6 S.M.S.A.	Ordinary	49.97
Green Energy Plus 7 S.M.S.A	Ordinary	49.97
Green Energy Plus 8 S.M.S.A.	Ordinary	49.97
Sunpower 1 S.M.P.C	Ordinary	49.97
International airport "El. Venizelos", Athens, Greece		
SAFCO SA	Ordinary	33.33
India		
3rd Floor, Maker Chambers IV, 222, Nariman Point, Mumbai, 400 021, India		
Reliance BP Mobility Limited	Ordinary	49.00
815-816 International Trade Tower, Nehru Place, 110019, New Delhi, Delhi, India		
Lightsource Renewable Energy India Opco Private Limited	Ordinary	49.97
LREHL Renewables India SPV 1 Private Limited	Ordinary	25.49
One Indiabulls Center, 16th Floor, Tower 2A, Senapati Bapat Marg, Mumbai City, Maharashtra, Mumbai, 400013, India		
Eversource Capital Private Limited	Ordinary	24.99
Unit Nos.71 & 737th Floor, Maker Maxity, 2nd North Avenue, Bandra - Kurla Complex, Bandra (East), Mumbai 400 051, Maharashtra, India		
India Gas Solutions Private Limited	Ordinary	50.00
Indonesia		
AKR Tower 25th floor, Jalan Panjang No.5, Kebon Jeruk, Jakarta, 11530, Indonesia		
PT. Aneka Petroindo Raya	Ordinary	49.90
Bakrie Tower 17th Floor, Rasuna Epicentrum Complex Jl. H.R Rasuna Said, Jakarta, 12940, Indonesia		
PT Petro Storindo Energi	Ordinary	30.00
Wisma AKR, 25th floor, Jalan Panjang No.5, Kebon Jeruk, Jakarta Barat, 11530, Indonesia		
PT. Dirgantara Petroindo Raya	Ordinary	49.90
Iraq		
Naz City, Building J, Suite 10 Erbil, Iraq		
Mach Monument Aviation Fuelling Co. Ltd.	Ordinary	70.00
Ireland		
Trinity House, Charleston Road Ranelagh, Ranelagh, Ireland		
Lightsource Ireland Development Holdings Limited	Ordinary	49.97
Lightsource Ireland SPV 6 Limited	Ordinary	49.97
Lightsource Labs Limited	Ordinary	49.97
Lightsource Renewable Energy Ireland Limited	Ordinary	49.97
Ubiworx Systems Designated Activity Company	Ordinary	49.97
Italy		
Via Giacomo Leopardi 7, Milan, CAP 20123, Italy		
Belenos s.r.l.	Membership Interest	32.48
Lightsource Renewable Energy Italy Development, S.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy Finco s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy Holdings, S.r.l.	Membership Interest	49.97
Lightsource Renewable Energy Italy SPV 1 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 10 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 11 S.r.l	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 2 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 3 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 4 s.r.l.	Ordinary	49.97

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14. Related undertakings of the group – continued

Lightsource Renewable Energy Italy SPV 6 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 7 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 8 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 9 s.r.l.	Ordinary	49.97
Pollon s.r.l.	Membership Interest	32.48
Via Sardegna, Rome, 38 00187, Italy		
Air BP Italia Spa	Ordinary	50.00
Via Venti Settembre, 69, Palermo, 90141, Italy		
Marsala Energie S.r.l.	Ordinary	49.97
Melilli Energie S.r.l.	Membership Interest	49.97
ML Energie Rinnovabili S.r.l.	Ordinary	49.97
Viale Francesco Scaduto, 2d, Palermo, 90144, Italy		
HF Solar 1 S.r.l.	Ordinary	49.97
HF Solar 2 S.r.l.	Ordinary	49.97
HF Solar 3 S.r.l.	Ordinary	49.97
HF Solar 4 S.r.l	Ordinary	49.97
HF Solar 5 S.r.l	Ordinary	49.97
Jersey		
IFC 5, St Helier, Jersey, JE1 1ST, Jersey		
In Salah Gas Limited	Ordinary B (51.00%)	25.50
In Salah Gas Services Limited	Ordinary B (51.00%)	25.50
Korea (the Republic of)		
3089, 30F, ASEM Tower, 517, Yeongdong-daero, Gangnam-gu, South Korea, 06170, Korea (the Republic of)		
Lightsource Renewable Energy Development South Korea Co., Ltd	Ordinary	49.97
Mauritius		
3rd Floor, Standard Chartered Tower, Bank Street, 19 Cybercity, Ebene, 72201, Mauritius		
EverSource Management Holdings	Ordinary	24.99
Mexico		
Av. Paseo de la Reforma 505 piso 32, Colonia Cuauhtémoc, Delegación Cuauhtémoc (06500), CDMX, Mexico		
EMSEP S.A. de C.V.	Ordinary	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 Energy S.A. de C.V.	Ordinary	50.00
Mozambique		
Parcela 729, via onze mil cento e trinta, numero cento e qua, Matola Lingamo, Mozambique		
SAMCOL - Sociedade de Armazenamento e Manuseamento de Combustiveis Liquidos, Limitada	Membership Interest	50.00
Praca Dos Trabalhadores, Nr 09, Distrito Urbano 1, Maputo, Mozambique		
Maputo International Airport Fuelling Services (MIAFS) Limitada	Membership Interest	50.00
Netherlands		
Anchoragelaan 6, 1118LD Luchthaven Schiphol, Netherlands		
Gezamenlijke Tankdienst Schiphol B.V.	Ordinary	50.00
Basisweg 10, 1043AP Amsterdam, Netherlands		
Lightsource BP Hassan Allam Holdings B.V.	Ordinary	24.99
Lightsource Renewable Energy Netherlands Development B.V.	Ordinary	49.97
Lightsource Renewable Energy Netherlands Holdings B.V.	Ordinary	49.97
Lightsource Renewable Energy Netherlands SPV 3 B.V.	Ordinary	49.97
Butaanweg 215, NL-3196 KC Vondelingenplaat, Rotterdam, Havennummer, 3045, Netherlands		
N.V. Rotterdam-Rijn-Pijpleiding Maatschappij (RRP)	Ordinary	44.40
Moezelweg 101, 3198LS Europoort, Rotterdam, Netherlands		
Maatschap Europoort Terminal	Partnership interest	50.00
Oude Vijfhuizerweg 6, 1118LV Luchthaven, Schiphol, Netherlands		
Aircraft Fuel Supply B.V.	Ordinary	28.57
Prins Bernhardplein 200, Amsterdam, 1097JB, Netherlands		
Lightsource Renewable Energy Netherlands SPV 1 B.V.	Ordinary	49.97
Lightsource Renewable Energy Netherlands SPV 2 B.V.	Ordinary	49.97
Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands		
BP AOC Pumpstation Maatschap	Partnership interest	50.00
BP Esso AOC Maatschap	Partnership interest	22.80
BP Esso Pipeline Maatschap	Partnership interest	50.00

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14. Related undertakings of the group – continued

Maasvlakte Europoort Pipeline Maatschap	Partnership interest	50.00
Team Terminal B.V.	Ordinary	22.80
Strawinskylaan 1725, 1077XX Amsterdam, Netherlands		
Routex B.V.	Ordinary	25.00
New Zealand		
10th Floor, The Bayleys Building, Cnr Brandon St and Lambton Quay, Wellington, 6011, New Zealand		
Coastal Oil Logistics Limited	Ordinary	25.00
399 Moray Place, Dunedin, 9016, New Zealand		
RD Petroleum Limited	Ordinary	49.00
KPMG, 247 Cameron Road, Tauranga, 3110, New Zealand		
McFall Fuel Limited	Ordinary	49.00
RMF Holdings Limited	Ordinary	49.00
Level 3, 139 The Terrace, Wellington, 6011, New Zealand		
New Zealand Oil Services Limited	Ordinary	50.00
Ross Pauling & Partners Limited, 106b Bush Road, Auckland, Albany, 0632, New Zealand		
Wiri Oil Services Limited	Ordinary	27.78
Norway		
Oksenoyveien 10, 1366 Lysaker, Norway		
Aker BP ASA	Ordinary	27.85
Postboks 133, Gardermoen, NO-2061, Norway		
Gardermoen Fuelling Services AS	Ordinary	33.33
Postboks 134, Gardermoen, NO-2061, Norway		
Oslo Lufthavns Tankanlegg AS	Ordinary	33.33
Postboks 36, Stjordal, NO-7501, Norway		
Flytanking AS	Ordinary	50.00
Oman		
P.O.Box 20302/211, 20302, Oman		
BP Dhofar LLC	Ordinary	49.00
Paraguay		
Av. España 1369 esquina San Rafael, Asunción, Paraguay		
Axion Energy Paraguay S.R.L.	Membership Interest	50.00
Peru		
Avenida Ricardo Rivera Navarrete n.501 / room 1602, Lima, Peru		
Air BP PBF del Peru S.A.C.	Ordinary	50.00
Poland		
Grunwaldzka 472B, Gdansk, 80-309, Poland		
Lotos - Air BP Polska Spółka z ograniczoną odpowiedzialnością	Ordinary	50.00
Macieja Rataja 28, 59–220 Legnica, Poland		
Wena Projekt 2 sp. z o.o.	Ordinary	49.97
ul. Andrzeja Struga 78, 90-557 Łódź, Poland		
RD PV PRODUKCJA 5 SPÓŁKA Z OGRANICZONA ODPOWIEDZIALNOSCIA	Ordinary	49.97
ul. Grzybowska 2/29, 00-131 Warszawa, Poland		
Frappato sp. z o.o.	Ordinary	49.97
Lightsource Development Polska sp. z o.o.	Ordinary	49.97
LS 6 sp. z.o.o.	Ordinary	49.97
ul. Towarowa 28, Warsaw, 00-839, Poland		
LS 1 sp. z.o.o.	Ordinary	49.97
LS 2 sp. z.o.o.	Ordinary	49.97
LS 3 sp. z.o.o.	Ordinary	49.97
LS 4 sp. z.o.o.	Ordinary	49.97
LS 5 sp. z.o.o.	Ordinary	49.97
LS 7 sp. z.o.o.	Ordinary	49.97
Portugal		
Grupo Operacional de Combustiveis do Aeroporto de Lisboa, Edificio 19, 1.º Sala Saba, Lisboa, Portugal		
SABA- Sociedade Abastecedora de Aeronaves, Lda	Ordinary	25.00
Rua Castilho 50, Lisbon, 1250 071, Portugal		
Brisas Excêntricas Unipessoal Lda	Ordinary	49.97
Coherent Modernity, Lda	Ordinary	49.97
Coloursflow - Unipessoal Lda	Ordinary	49.97

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14. Related undertakings of the group – continued

Crystalline Parallel - Unipessoal Lda	Ordinary	49.97
Forest Constellation - Unipessoal Lda	Ordinary	49.97
Freshpanoply - Lda	Ordinary	49.97
Ignichoice Renewable Energy V, Unipessoal LDA	Ordinary	49.97
Ignidap – Energias Renováveis, Unipessoal Lda	Ordinary	49.97
Ramisun – Consultoria e Energias Renováveis, Unipessoal Lda.	Ordinary	49.97
Solid Tomorrow - Energia Unipessoal Lda	Ordinary	49.97
Suninger - Consultoria e Energias Renováveis, Unipessoal Lda	Ordinary	49.97
Tolerantdiagonal - Lda	Ordinary	49.97
Violetdynasty Unipessoal Lda	Ordinary	49.97
Rua Júlio Dinis, n.º 247, 6.º, E-1, Edifício Mota Galiza, Parish of Lordelo do Ouro and Massarelos, Porto, 4050-324, Portugal		
Dapsun - Investimentos e Consultoria, LDA.	Ordinary	25.23
Rua Sousa Martins, no 10, Lisboa, 1050 218, Portugal		
Compatibleglobe, Lda	Ordinary	49.97
Lightsource Renewable Energy Portugal (HoldCo), Lda.	Ordinary	49.97
Romania		
59 Aurel Vlaicu Street, Otopeni, Ilfov County, Romania		
Romanian Fuelling Services S.R.L.	Ordinary	50.00
Russian Federation[h]		
26/1 Sofiyskaya Embankment, Moscow, 115035, Russian Federation		
Rosneft Oil Company	Ordinary	19.75
629830 Yamalo-Nenetskiy Anatomy Region, city of Gubkinskiy, Russian Federation		
LLC "Kharampurneftegaz"	Membership Interest	49.00
Kosmodamianskaya embarkment, 52 bldg 3, floor 9, unit 29, Moscow, 115035, Russian Federation		
Srednelenskoye Limited Liability Company	Membership Interest	49.00
Kosmodamianskaya nab, 52/3, Moscow, 115035, Russian Federation		
Limited Liability Company Yermak Neftegaz	Membership Interest	49.00
Pervomayskaya street, 32A, Sakha (Yakutiya) Republic, Lensk, 678144, Russian Federation		
Lensky Nefteprovod Limited Liability Company	Membership Interest	20.00
Limited Liability Company TYNGD	Membership Interest	20.00
Saudi Arabia		
P O Box 6369, Jeddah21442, Saudi Arabia		
Peninsular Aviation Services Company Limited[e]	Membership Interest	50.00
Riyadh Airport Road, Business Gate, Building C2, 2nd Floor., Saudi Arabia		
Arabian Production And Marketing Lubricants Company	Ordinary	50.00
Singapore		
112 Robinson Road, #05-01, Robinson 112, 068902, Singapore		
BP Sinopec Marine Fuels Pte. Ltd.	Ordinary	50.00
163 Penang Road, #08-01, Winsland House II, 238463, Singapore		
Green Growth Feeder Fund Pte. Ltd	Ordinary	24.99
8 Marina Boulevard, #05-02, Marina Bay Financial Centre, 018981, Singapore		
Lightsource Singapore Renewables Holdings Private Limited	Ordinary	49.97
Lightsource Singapore Renewables Private Limited	Ordinary	49.97
8 Temasek Boulevard #31-02, Suntec City Tower 3, Singapore 038988, Singapore		
China Aviation Oil (Singapore) Corporation Ltd	Ordinary	20.17
South Africa		
1 Refinery Road, Prospecton, 4110, South Africa		
Shell and BP South African Petroleum Refineries (Pty) Ltd	Ordinary A	37.45
135 Honshu Road, Islandview, Durban, 4052, South Africa		
Blendcor (Pty) Limited	Ordinary B	37.45
Spain		
Arbea Campus Empresarial, Edifico 1. Ctra de Fuencarral a Alcobendas, M603, KM 3,8 28108 Alcobendas, Madrid, Spain		
Axion Energy Holding S.L.	Membership Interest	50.00
Hokchi Iberica S.L.	Ordinary	50.00
Pan American Energy Group, S.L.	Ordinary B	50.00
Pan American Energy Iberica S.L.	Ordinary	50.00
Pan American Energy, S.L.	Membership Interest	50.00

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14. Related undertakings of the group – continued

Avenida Academia General Militar, 52, Aragón, Zaragoza, 50015, Spain		
Almendra Renovables 400KV, S.L.	Ordinary	26.87
Colectora Hiberus-Libienergy, S.L.	Ordinary	24.99
Gestión Rueda Promotores, S.L.	Ordinary	23.95
Jorge Energy I, S.L.U.	Ordinary	49.97
Jorge Energy IV, S.L.U.	Ordinary	49.97
Sinergia Aragonesa, S.L.U.	Ordinary	49.97
C/ Velazquez 64-66, Spain		
Expansion Habit, S.L.U.	Ordinary	24.49
C/Pradillo 5, Bajo Exterior Derecha, Madrid, 28002, Spain		
Lightsource Renewable Energy Trading, SL	Ordinary	49.97
Calle Alcala numero 63, Madrid, 28014, Spain		
Aragonesa de Gestión de Energías Alternativas, SL	Ordinary	49.97
Ateca Renovables, S.L.	Ordinary	24.99
Energías Renovables de Ixion, SL	Ordinary	49.97
Fuerzas Energéticas del Sur de Europa IV, SL	Ordinary	49.97
Fuerzas Energéticas del Sur de Europa XIX, SL	Ordinary	49.97
Fuerzas Energéticas del Sur de Europa, S.L.U	Ordinary	49.97
Gómez Narro Renovables 132 kV, A.I.E	Membership Interest	49.97
Implantación de Fuentes Energéticas de Origen Renovable, SL	Ordinary	49.97
Lightsource Renewable Energy Cariñena S.L.	Ordinary	49.97
Lightsource Renewable Energy Garnacha, S.L.	Ordinary	49.97
Lightsource Renewable Energy Spain Development, SL	Ordinary	49.97
Lightsource Renewable Energy Spain Holdings, SL	Ordinary	49.97
Lightsource Renewable Energy Spain SPV 1, SL	Ordinary	49.97
Modelos Energéticos Sostenibles, S.L.	Ordinary	49.97
Modelos Energéticos Sostenibles, S.L.U.	Ordinary	49.97
Vendimia Grid, AIE	Ordinary	49.97
Calle Jose Ortega y Gasset 22-24, 2nd Floor, 28006 Madrid, Spain		
Performan Lark, S.L.U.	Ordinary	49.97
Calle jose Ortega y Gasset, 20 - 2ª Planta, Madrid, 28006, Spain		
Energía Inagotable de Eolo, S.L.U.	Ordinary	49.97
Calle Lituania nº 10, Castellón de la Plana, Spain		
Fundación para la Eficiencia Energética de la Comunidad Valenciana	Membership Interest	33.33
Calle Suero de Quinones, Numero 34-36, Madrid, 28002, Spain		
Lightsource Europe Asset Management, SL	Ordinary	49.97
Lightsource Spain O&M, SL	Ordinary	49.97
Carretera de San Andréss/n, La Jurada-María Jiménez, Santa Cruz de Tenerife, Spain		
Terminales Canarios, S.L.	Ordinary	50.00
Paseo de la Castellana 140, 7C, 28046 Madrid, Spain		
Alejandria Power, S.L.U.	Ordinary	49.97
KHONS SUN POWER, S.L.U.	Ordinary	49.97
Rin Power, S.L.U.	Ordinary	49.97
Sinfonia Solar Energy Power, S.L.U.	Ordinary	49.97
Paseo de la Castellana 278, Madrid, Spain		
Servicios Logísticos de Combustibles de Aviación, S.L	Ordinary	50.00
Paseo del Mar, 6, San roque, Cadiz, 11312, Spain		
ISC Greenfield 12, S.L.	Ordinary	49.97
ISC Greenfield 7, S.L.	Ordinary	49.97
Parque FV Borealis, S.L.	Ordinary	49.97
Parque FV Polaris, S.L.	Ordinary	49.97
Sweden		
Box 135, 190 46 Arlanda, Sweden		
A Flygbranslehantering AB (AFAB)	Ordinary	25.00
Box 2154, Landvetter, 438 14, Sweden		
Gothenburgh Fuelling Company AB (GFC)	Ordinary	33.33
Box 22, SE 230 32 Malmö-Sturup, Sweden		
Malmo Fuelling Services AB	Ordinary	33.33

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14. Related undertakings of the group – continued

Box 7, 190 45 Arlanda, Sweden		
Stockholm Fuelling Services Aktiebolag	Ordinary	25.00
Switzerland		
Auhafenstrasse 10a, Muttenz, 4132, Switzerland		
TAU Tanklager Auhafen AG	Ordinary	50.00
Birmenstorferstrasse 2, Mellingen, 5507, Switzerland		
Tankanlage AG Mellingen	Ordinary	33.33
Lindenstrasse 2, 6340 Baar, Switzerland		
Trans Adriatic Pipeline AG	Ordinary	20.00
Nideracher 1, Niederurnen, 8867, Switzerland		
Raststaette Glarnerland AG, Niederurnen	Ordinary	20.00
Route de Pré-Bois 17, Cointrin, 1216, Switzerland		
Saraco SA	Ordinary	20.00
route de Pré-Bois 2, Vernier, 1214, Switzerland		
Petrostock SA	Ordinary	50.00
Zwüscheteich, Rümlang, 8153, Switzerland		
TAR - Tankanlage Ruemlang AG	Ordinary	27.32
Taiwan		
11F, No. 235, Section 4, Zhong Xiao East Road,Da'an district, Taipei City, 10692, Taiwan		
Hui-Meng Energy Co., Ltd.	Ordinary	49.97
17F, No. 97, Songren Rd, Xinyi Dist, Taipei City, 110050, Taiwan		
Lightsource Renewable Energy Development Taiwan Limited	Ordinary	49.97
Thailand		
23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand		
Pacroy (Thailand) Co., Ltd.	Ordinary (100.00%); Preference (0.82%)	39.50
Trinidad and Tobago		
48-50 Sackville Street, Port of Spain, Trinidad and Tobago		
Brechin Castle Solar Limited	Ordinary	49.97
Orange Grove Solar Limited	Ordinary	49.97
Solar Photovoltaic Development Company (Trinidad and Tobago) Limited	Ordinary	49.97
Solar Photovoltaic Holding Company of Trinidad and Tobago Limited	Ordinary	49.97
Princes Court, Cor. Pembroke & Keate Street, Port-of-Spain, Trinidad and Tobago		
Atlantic LNG 2/3 Company of Trinidad and Tobago Unlimited	Ordinary	42.50
Atlantic LNG 4 Company of Trinidad and Tobago Unlimited	Ordinary	37.78
Atlantic LNG Company of Trinidad and Tobago	Ordinary	34.00
Turkey		
Degirmen yolu cad. No:28, Asia OfisPark K:3 Icerenkoy-Atasehir, Istanbul, 34752, Turkey		
ATAS Anadolu Tasfiyehanesi Anonim Sirketi[f]	Ordinary	68.00
Liman Mah. 60 Sk., Çekisan-Idari Bina sit. No:25 A/1, Konyaalti, Antalya, Turkey		
Cekisan Depolama Hizmetleri Limited Sirketi	Ordinary	35.00
Yakuplu Mahallesi Genc, Osman Caddesi, No.7 Beylikdüzü, Istanbul, Turkey		
Ambarli Depolama Hizmetleri Limited Sirketi	Ordinary	50.00
United Arab Emirates		
6th Flr City Tower, 2 - Sheikh Zayed Road, PO Box 1699, Dubai, United Arab Emirates		
Middle East Lubricants Company LLC	Ordinary	29.33
LOB 16, Suite #309, Dubai, Jebel Ali Free Zone, PO BOX 262794, United Arab Emirates		
SKA Energy Holdings Limited	Ordinary	50.00
P O Box- 97, Sharjah, United Arab Emirates		
Sharjah Aviation Services Co. LLC	Ordinary B	49.00
P.O.Box 261781, Dubai, United Arab Emirates		
EMDAD Aviation Fuel Storage FZCO	Ordinary	33.33
Plot No. B003R04, Box No. 9400, Dubai, United Arab Emirates, Dubai, United Arab Emirates		
Emoil Storage Company FZCO	Ordinary	20.00
Sharjah 42244, Sharjah, United Arab Emirates		
Sharjah Pipeline Company LLC	Ordinary	49.00
Unit GD-GB-00-15-BC-26, Level 15, Gate District Gate Building, Dubai International Financial Center, 74777, United Arab Emirates		
Basra Energy Company Limited	Ordinary	49.00

14. Related undertakings of the group – continued

United Kingdom		
1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom		
BP-Japan Oil Development Company Limited	Ordinary A; Deferred ordinary	50.00
S&JD Robertson North Air Limited	Ordinary	49.00
12-14 Carlton Place, Southampton, SO15 2EA, United Kingdom		
Blue Ocean Seismic Services Limited	Ordinary (0.00%); Preference (52.50%)	23.33
121A Thoday Street, Cambridge, Cambridgeshire, CB1 3AT, United Kingdom		
Foreseer Ltd	Membership Interest	25.00
2 Chester Row, London, SW1W 9JH, United Kingdom		
Green Biofuels Limited	Ordinary	30.00
33 Cavendish Square, London, W1G 0PW, United Kingdom		
Great Ropemaker Partnership (G.P.) Limited	Ordinary B	50.00
Great Ropemaker Property (Nominee 1) Limited	Ordinary	50.00
Great Ropemaker Property (Nominee 2) Limited	Ordinary	50.00
Great Ropemaker Property Limited	Ordinary	50.00
The Great Ropemaker Partnership	Membership Interest	50.00
522 Fulham Road, London, SW6 5NR, United Kingdom		
Alyssum Group Limited	Membership Interest	26.23
5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS, United Kingdom		
United Kingdom Oil Pipelines Limited	Ordinary	22.15
Walton-Gatwick Pipeline Company Limited	Ordinary	42.33
West London Pipeline and Storage Limited	Ordinary	30.50
60 Sloane Avenue, London, SW3 3XB, United Kingdom		
Fly Victor Ltd	Membership Interest	26.23
6th Floor, 60 Gracechurch Street, London, EC3V 0HR, United Kingdom		
Gasrec Ltd	Ordinary A	28.52
7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom		
Aashman Power Limited	Ordinary	49.97
Bodmin Solar Limited	Ordinary	49.97
Burnthouse Solar Limited	Ordinary	49.97
Chittering Solar Limited	Ordinary	49.97
Donoma Power Limited	Ordinary	49.97
Ffos Las Solar Developments Limited	Ordinary	49.97
Free Power for Schools 13 Limited	Ordinary	49.97
Free Power for Schools 14 Limited	Ordinary	49.97
Free Power for Schools 15 Limited	Ordinary	49.97
Free Power for Schools 17 Limited	Ordinary	49.97
Free Power for Schools 19 Limited	Ordinary	49.97
Free Power for Schools 4 Limited	Ordinary	49.97
Free Power for Schools 5 Limited	Ordinary	49.97
Free Power for Schools 6 Limited	Ordinary	49.97
Free Power for Schools 7 Limited	Ordinary	49.97
Freetricity Central June Limited	Ordinary	49.97
Freetricity Commercial June Limited	Ordinary	49.97
Gnowee Power Limited	Ordinary	49.97
H7 Energy Limited	Ordinary	49.97
Howbery Solar Park Limited	Ordinary	49.97
Kala Power Limited	Ordinary	49.97
Lightsource Asset Holdings (Australia) Ltd	Ordinary	49.97
Lightsource Asset Holdings (Europe) Limited	Ordinary	49.97
Lightsource Asset Holdings (Spain) Limited	Ordinary	49.97
Lightsource Asset Holdings (UK) Limited	Ordinary	49.97
Lightsource Asset Holdings (USA) Limited	Ordinary	49.97
Lightsource Asset Holdings (Vendimia I) Limited	Ordinary	49.97
Lightsource Asset Holdings (Vendimia II) Limited	Ordinary	49.97
Lightsource Asset Holdings 1 Limited	Ordinary	49.97
Lightsource Asset Holdings 2 Limited	Ordinary	49.97
Lightsource Asset Holdings 3 Limited	Ordinary	49.97

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14. Related undertakings of the group – continued

Lightsource Asset Management Limited	Ordinary	49.97
Lightsource Australia FinCo Holdings Limited	Ordinary	49.97
Lightsource Bodegas 2 Limited	Ordinary	49.97
Lightsource Bodegas 3 Limited	Ordinary	49.97
Lightsource Bodegas 4 Limited	Ordinary	49.97
Lightsource Bodegas Limited	Ordinary	49.97
Lightsource BP Renewable Energy Investments Limited	Ordinary A (49.97%); Ordinary C (49.96%); Ordinary D (50.00%); Ordinary E (50.00%); Ordinary F (49.95%); Ordinary G (50.00%)	49.97
Lightsource Brazil Holdings 1 Limited	Ordinary	49.97
Lightsource Brazil Holdings 2 Limited	Ordinary	49.97
Lightsource Commercial Rooftops (Buyback) Limited	Ordinary	49.97
Lightsource Commercial Rooftops Limited	Ordinary	49.97
Lightsource Construction Management Limited	Ordinary	49.97
Lightsource Corinthian Limited	Ordinary	49.97
Lightsource Development Services Limited	Ordinary	49.97
Lightsource Egypt Holdings Limited	Ordinary	49.97
Lightsource Elk Hill 2 Solar Limited	Ordinary	49.97
Lightsource Elk Hill Solar 2 Holdings Limited	Ordinary	49.97
Lightsource Finance 55 Limited	Ordinary	49.97
Lightsource Finca 2 Limited	Ordinary	49.97
Lightsource Finca 3 Limited	Ordinary	49.97
Lightsource Finca Limited	Ordinary	49.97
Lightsource France Holdings UK Limited	Ordinary	49.97
Lightsource Grace 1 Limited	Ordinary	49.97
Lightsource Grace 2 Limited	Ordinary	49.97
Lightsource Grace 3 Limited	Ordinary	49.97
Lightsource Holdings 1 Limited	Ordinary	49.97
Lightsource Holdings 2 Limited	Ordinary	49.97
Lightsource Holdings 3 Limited	Ordinary	49.97
Lightsource Iberia Greenfield Holdings Limited	Ordinary	49.97
Lightsource Iberia Project Holdings Limited	Ordinary	49.97
Lightsource Impact 1 Limited	Ordinary	49.97
Lightsource Impact 2 Limited	Ordinary	49.97
Lightsource India Holdings (Mauritius) Limited	Ordinary	49.97
Lightsource India Holdings Limited	Ordinary	49.97
Lightsource India Investments (UK) Limited	Ordinary	49.97
Lightsource India Limited	Ordinary A	25.49
Lightsource India Maharashtra 1 Holdings Limited	Ordinary	49.97
Lightsource India Maharashtra 1 Limited	Ordinary	49.97
Lightsource Kingfisher Holdings Limited	Ordinary	49.97
Lightsource Kingpin 1 Limited	Ordinary	49.97
Lightsource Kingpin 2 Limited	Ordinary	49.97
Lightsource Kingpin 3 Limited	Ordinary	49.97
Lightsource Labs 1 Limited	Ordinary	49.97
Lightsource Labs Holdings Limited	Ordinary	49.97
Lightsource Largescale Limited	Ordinary	49.97
Lightsource Manzanilla Limited	Ordinary	49.97
Lightsource Midscale Limited	Ordinary	49.97
Lightsource Nala Limited	Ordinary	49.97
Lightsource Operations 1 Limited	Ordinary	49.97
Lightsource Operations 2 Limited	Ordinary	49.97
Lightsource Operations 3 Limited	Ordinary	49.97
Lightsource Operations Services Limited	Ordinary	49.97
Lightsource Poland Holdings (UK) Limited	Ordinary	49.97
Lightsource Property 1 Limited	Ordinary	49.97
Lightsource Property 2 Limited	Ordinary	49.97

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14. Related undertakings of the group – continued

Lightsource Property Investment Holdings Ltd	Ordinary	49.97
Lightsource Property Investment Management (LPIM) LLP	Membership Interest	49.97
Lightsource Property Investments 1 Ltd	Ordinary	49.97
Lightsource Pumbaa Limited	Ordinary	49.97
Lightsource Radiate 1 Limited	Ordinary	49.97
Lightsource Radiate 2 Limited	Ordinary	49.97
Lightsource Raindrop Limited	Ordinary	49.97
Lightsource Renewable Energy (India) Limited	Ordinary	49.97
Lightsource Renewable Energy Asia Pacific Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy Australia Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy Greece Holdings (UK) Limited	Ordinary	49.97
Lightsource Renewable Energy Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy Iberia Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy India Assets Limited	Ordinary	49.97
Lightsource Renewable Energy India Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy India Projects Limited	Ordinary	49.97
Lightsource Renewable Energy Italy Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy Limited	Ordinary	49.97
Lightsource Renewable Energy Moristel Limited	Ordinary	49.97
Lightsource Renewable Energy Netherlands Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy Poland Projects 1 Limited	Ordinary	49.97
Lightsource Renewable Energy Poland Projects 2 Limited	Ordinary	49.97
Lightsource Renewable Energy Portugal Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy Portugal Projects 1 Limited	Ordinary	49.97
Lightsource Renewable Energy Portugal Projects 2 Limited	Ordinary	49.97
Lightsource Renewable Energy Tempranillo Limited	Ordinary	49.97
Lightsource Renewable Energy Verdejo Limited	Ordinary	49.97
Lightsource Renewable Global Development Limited	Ordinary	49.97
Lightsource Renewable Services Limited	Ordinary	49.97
Lightsource Renewable Taiwan UK Holdings Limited	Ordinary	49.97
Lightsource Renewable UK Development Limited	Ordinary	49.97
Lightsource Residential Rooftops (Buyback) Limited	Ordinary	49.97
Lightsource Residential Rooftops (PPA) Limited	Ordinary	49.97
Lightsource Residential Rooftops Limited	Ordinary	49.97
Lightsource Simba Limited	Ordinary	49.97
Lightsource SPV 10 Limited	Ordinary	49.97
Lightsource SPV 100 Limited	Ordinary	49.97
Lightsource SPV 101 Limited	Ordinary	49.97
Lightsource SPV 105 Limited	Ordinary	49.97
Lightsource SPV 106 Limited	Ordinary	49.97
Lightsource SPV 108 Limited	Ordinary	49.97
Lightsource SPV 109 Limited	Ordinary	49.97
Lightsource SPV 112 Limited	Ordinary	49.97
Lightsource SPV 114 Limited	Ordinary	49.97
Lightsource SPV 115 Limited	Ordinary	49.97
Lightsource SPV 116 Limited	Ordinary	49.97
Lightsource SPV 118 Limited	Ordinary	49.97
Lightsource SPV 123 Limited	Ordinary	49.97
Lightsource SPV 126 Limited	Ordinary	49.97
Lightsource SPV 127 Limited	Ordinary	49.97
Lightsource SPV 128 Limited	Ordinary	49.97
Lightsource SPV 130 Limited	Ordinary	49.97
Lightsource SPV 135 Limited	Ordinary	49.97
Lightsource SPV 138 Limited	Ordinary	49.97
Lightsource SPV 140 Limited	Ordinary	49.97
Lightsource SPV 142 Limited	Ordinary	49.97
Lightsource SPV 143 Limited	Ordinary	49.97
Lightsource SPV 145 Limited	Ordinary	49.97
Lightsource SPV 149 Limited	Ordinary	49.97

The parent company financial statements of BP p.l.c. on pages 282-336 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 151 Limited	Ordinary	49.97
Lightsource SPV 152 Limited	Ordinary	49.97
Lightsource SPV 154 Limited	Ordinary	49.97
Lightsource SPV 160 Limited	Ordinary	49.97
Lightsource SPV 162 Limited	Ordinary	49.97
Lightsource SPV 166 Limited	Ordinary	49.97
Lightsource SPV 167 Limited	Ordinary	49.97
Lightsource SPV 169 Limited	Ordinary	49.97
Lightsource SPV 170 Limited	Ordinary	49.97
Lightsource SPV 171 Limited	Ordinary	49.97
Lightsource SPV 174 Limited	Ordinary	49.97
Lightsource SPV 175 Limited	Ordinary	49.97
Lightsource SPV 176 Limited	Ordinary	49.97
Lightsource SPV 179 Limited	Ordinary	49.97
Lightsource SPV 18 Limited	Ordinary	49.97
Lightsource SPV 180 Limited	Ordinary	49.97
Lightsource SPV 182 Limited	Ordinary	49.97
Lightsource SPV 183 Limited	Ordinary	49.97
Lightsource SPV 184 Limited	Ordinary	49.97
Lightsource SPV 185 Limited	Ordinary	49.97
Lightsource SPV 187 Limited	Ordinary	49.97
Lightsource SPV 189 Limited	Ordinary	49.97
Lightsource SPV 19 Limited	Ordinary	49.97
Lightsource SPV 191 Limited	Ordinary	49.97
Lightsource SPV 192 Limited	Ordinary	49.97
Lightsource SPV 196 Limited	Ordinary	49.97
Lightsource SPV 199 Limited	Ordinary	49.97
Lightsource SPV 20 Limited	Ordinary	49.97
Lightsource SPV 200 Limited	Ordinary	49.97
Lightsource SPV 201 Limited	Ordinary	49.97
Lightsource SPV 202 Limited	Ordinary	49.97
Lightsource SPV 203 Limited	Ordinary	49.97
Lightsource SPV 204 Limited	Ordinary	49.97
Lightsource SPV 205 Limited	Ordinary	49.97
Lightsource SPV 206 Limited	Ordinary	49.97
Lightsource SPV 212 Limited	Ordinary	49.97
Lightsource SPV 213 Limited	Ordinary	49.97
Lightsource SPV 214 Limited	Ordinary	49.97
Lightsource SPV 215 Limited	Ordinary	49.97
Lightsource SPV 216 Limited	Ordinary	49.97
Lightsource SPV 217 Limited	Ordinary	49.97
Lightsource SPV 222 Limited	Ordinary	49.97
Lightsource SPV 223 Limited	Ordinary	49.97
Lightsource SPV 224 Limited	Ordinary	49.97
Lightsource SPV 232 Limited	Ordinary	49.97
Lightsource SPV 233 Limited	Ordinary	49.97
Lightsource SPV 236 Limited	Ordinary	49.97
Lightsource SPV 242 Limited	Ordinary	49.97
Lightsource SPV 247 Limited	Ordinary	49.97
Lightsource SPV 25 Limited	Ordinary	49.97
Lightsource SPV 258 Limited	Ordinary	49.97
Lightsource SPV 259 Limited	Ordinary	49.97
Lightsource SPV 26 Limited	Ordinary	49.97
Lightsource SPV 261 Limited	Ordinary	49.97
Lightsource SPV 263 Limited	Ordinary	49.97
Lightsource SPV 264 Limited	Ordinary	49.97
Lightsource SPV 286 Limited	Ordinary	49.97
Lightsource SPV 287 Limited	Ordinary	49.97
Lightsource SPV 29 Limited	Ordinary	49.97

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14. Related undertakings of the group – continued

Lightsource SPV 32 Limited	Ordinary	49.97
Lightsource SPV 35 Limited	Ordinary	49.97
Lightsource SPV 39 Limited	Ordinary	49.97
Lightsource SPV 40 Limited	Ordinary	49.97
Lightsource SPV 41 Limited	Ordinary	49.97
Lightsource SPV 42 Limited	Ordinary	49.97
Lightsource SPV 44 Limited	Ordinary	49.97
Lightsource SPV 47 Limited	Ordinary	49.97
Lightsource SPV 49 Limited	Ordinary	49.97
Lightsource SPV 5 Limited	Ordinary	49.97
Lightsource SPV 50 Limited	Ordinary	49.97
Lightsource SPV 54 Limited	Ordinary	49.97
Lightsource SPV 56 Limited	Ordinary	49.97
Lightsource SPV 60 Limited	Ordinary	49.97
Lightsource SPV 69 Limited	Ordinary	49.97
Lightsource SPV 73 Limited	Ordinary	49.97
Lightsource SPV 74 Limited	Ordinary	49.97
Lightsource SPV 75 Limited	Ordinary	49.97
Lightsource SPV 76 Limited	Ordinary	49.97
Lightsource SPV 78 Limited	Ordinary	49.97
Lightsource SPV 79 Limited	Ordinary	49.97
Lightsource SPV 8 Limited	Ordinary	49.97
Lightsource SPV 88 Limited	Ordinary	49.97
Lightsource SPV 91 Limited	Ordinary	49.97
Lightsource SPV 92 Limited	Ordinary	49.97
Lightsource SPV 98 Limited	Ordinary	49.97
Lightsource Timon Limited	Ordinary	49.97
Lightsource Titan Borrower AUD Limited	Ordinary	49.97
Lightsource Titan Borrower EUR Limited	Ordinary	49.97
Lightsource Titan Borrower GBP Limited	Ordinary	49.97
Lightsource Titan Borrower USD Limited	Ordinary	49.97
Lightsource Titan Limited	Ordinary	49.97
Lightsource Trading Limited	Ordinary	49.97
Lightsource Trinidad Holdings (UK) Limited	Ordinary	49.97
Lightsource UK Property Investments 1 LP	Membership Interest	49.98
Lightsource Viking 1 Limited	Ordinary	49.97
Lightsource Viking 2 Limited	Ordinary	49.97
Lightsource Xenium 1 Limited	Ordinary	49.97
Lightsource Xenium 2 Limited	Ordinary	49.97
LL Property Services 2 Limited	Ordinary	49.97
LL Property Services Limited	Ordinary	49.97
Lora Solar Limited	Ordinary	49.97
Manor Farm (Solar Power) Limited	Ordinary	49.97
Meri Power Limited	Ordinary	49.97
MTS Francis Court Solar Limited	Ordinary	49.97
MTS Trefinnick Solar Limited	Ordinary	49.97
Nextpower Trevemper Limited	Ordinary	49.97
Nima Power Limited	Ordinary	49.97
Palk Power Limited	Ordinary	49.97
Pont Andrew Limited	Ordinary	49.97
Sel PV 09 Limited	Ordinary	49.97
Shakti Power Limited	Ordinary	49.97
Solar Photovoltaic (SPV2) Limited	Ordinary	49.97
Solar Photovoltaic (SPV3) Limited	Ordinary	49.97
Sula Power Limited	Ordinary	49.97
Sun and Soil Renewable 12 Limited	Ordinary	49.97
TGC Solar 106 Limited	Ordinary	49.97
TGC Solar 91 Limited	Ordinary	49.97
Thames Electricity Limited	Ordinary	49.97

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14. Related undertakings of the group – continued

Tiln Connections Ltd	Ordinary	49.97
Tonatiuh Trading 1 Limited	Ordinary	49.97
Tuwale Power Limited	Ordinary	49.97
TWQE2 Limited	Ordinary	49.97
West Wyalong HoldCo 1 Limited	Ordinary	49.97
Woolooga HoldCo 1 Limited	Ordinary	49.97
Your Power No. 1 Limited	Ordinary	49.97
Your Power No. 10 Limited	Ordinary	49.97
Your Power No. 12 Limited	Ordinary	49.97
Your Power No. 19 Limited	Ordinary	49.97
Your Power No. 2 Limited	Ordinary	49.97
Your Power No. 3 Limited	Ordinary	49.97
Your Power No. 8 Limited	Ordinary	49.97
Calshot Way Central Area, Heathrow Airport, Hounslow, Middlesex, TW6 1PY, United Kingdom		
Aviation Fuel Services Limited	Ordinary	25.00
Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom		
Mona Offshore Wind Holdings Limited	Ordinary	50.00
Mona Offshore Wind Limited	Ordinary	50.00
Morgan Offshore Wind Holdings Limited	Ordinary	50.00
Morgan Offshore Wind Limited	Ordinary	50.00
Eni House, 10 Ebury Bridge Road, London, SW1W 8PZ, United Kingdom		
VIC CBM Limited	Ordinary	50.00
Virginia Indonesia Co. CBM Limited	Ordinary	50.00
Kelvin Building , Bramah Avenue , East Kilbride, Glasgow , Scotland, G75 0RD, United Kingdom		
Heliex Power Limited	Membership Interest	32.40
Mw1 Building 557 Shoreham Road, Heathrow Airport, London,TW6 3RT, United Kingdom		
Aviation Service (Iraq) Limited	Ordinary B	40.00
Northgate House, 2nd Floor, Upper Borough Walls, Bath, BA1 1RG, United Kingdom		
Blue Marble Holdings Limited	Ordinary C (96.53%)	23.58
One Bartholomew Close, London, EC1A 7BL, United Kingdom		
Manchester Airport Storage and Hydrant Company Limited	Ordinary	25.00
Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom		
Lightsource Renewable Energy (NI) Limited	Ordinary	49.97
Lightsource Residential NI Limited	Ordinary	49.97
Lightsource SPV 266 (NI) Limited	Ordinary	49.97
Lightsource SPV 267 (NI) Limited	Ordinary	49.97
Lightsource SPV 268 (NI) Limited	Ordinary	49.97
Lightsource SPV 269 (NI) Limited	Ordinary	49.97
Lightsource SPV 270 (NI) Limited	Ordinary	49.97
Lightsource SPV 271 (NI) Limited	Ordinary	49.97
Lightsource SPV 272 (NI) Limited	Ordinary	49.97
Lightsource SPV 273 (NI) Limited	Ordinary	49.97
Lightsource SPV 274 (NI) Limited	Ordinary	49.97
Lightsource SPV 275 (NI) Limited	Ordinary	49.97
Lightsource SPV 276 (NI) Limited	Ordinary	49.97
Lightsource SPV 277 (NI) Limited	Ordinary	49.97
Lightsource SPV 278 (NI) Limited	Ordinary	49.97
Lightsource SPV 279 (NI) Limited	Ordinary	49.97
Lightsource SPV 280 (NI) Limited	Ordinary	49.97
Lightsource SPV 281 (NI) Limited	Ordinary	49.97
Lightsource SPV 282 (NI) Limited	Ordinary	49.97
Lightsource SPV 283 (NI) Limited	Ordinary	49.97
Lightsource SPV 284 (NI) Limited	Ordinary	49.97
Lightsource SPV 285 (NI) Limited	Ordinary	49.97
Shell Centre, London, SE1 7NA, United Kingdom		
Shell Mex and B.P. Limited	Ordinary B	40.00
SM Realisations Limited	Membership Interest	40.00
The Consolidated Petroleum Company Limited	Ordinary B	50.00
The Consolidated Petroleum Supply Company Limited[9]	Ordinary	50.00

The parent company financial statements of BP p.l.c. on pages 282-336 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

Suite 44 (C/O Best4Business Accountants), Beaufort Court, Admirals Way, London, E14 9XL, United Kingdom		
Pentland Aviation Fuelling Services Limited	Ordinary A; Ordinary B	66.67
Woodwater House, Pynes Hill, Exeter, EX2 5WR, United Kingdom		
Wick Farm Grid Limited	Ordinary	49.97
United States		
1209 Orange Street, Wilmington DE 19801, United States		
Ash Grove Renewable Energy, LLC	Membership Interest	47.50
Auwahi Holdings, LLC	Membership Interest	50.00
Auwahi Wind Energy LLC	Membership Interest	50.00
Belmont Technology Inc.	Preference A	37.50
BP-Husky Refining LLC	Membership Interest	50.00
Caesar Oil Pipeline Company, LLC	Membership Interest	39.39
CE BP Renew Co, LLC	Membership Interest	50.00
CE bp Renew Dynamic Co I, LLC	Membership Interest	40.00
CE bp Renew Dynamic Co II, LLC	Membership Interest	47.50
Cedar Creek II Holdings LLC	Membership Interest	50.00
Cefari RNG OKC, LLC	Membership Interest	50.00
Chicap Pipe Line Company	Membership Interest	28.65
Clean Eagle RNG, LLC	Membership Interest	50.00
Cleopatra Gas Gathering Company, LLC	Membership Interest	37.28
Drumgoon Digester Renewable Energy, LLC	Membership Interest	47.50
Endymion Oil Pipeline Company, LLC	Membership Interest	45.72
Flat Ridge 2 Wind Energy LLC	Membership Interest	50.00
Flat Ridge 2 Wind Holdings LLC	Membership Interest	50.00
Flat Ridge Interconnection LLC	Membership Interest	50.00
Fowler II Holdings LLC	Membership Interest	50.00
Fowler Ridge II Wind Farm LLC	Membership Interest	50.00
Fowler Ridge Wind Farm LLC	Membership Interest	100.00
Goshen Phase II LLC	Membership Interest	50.00
Marshall Ridge Renewable Energy, LLC	Membership Interest	47.50
Mavrix, LLC	Membership Interest	50.00
Mehoopany Wind Energy LLC	Membership Interest	50.00
Mehoopany Wind Holdings LLC	Membership Interest	50.00
Olympic Pipe Line Company LLC	Membership Interest	35.70
Proteus Oil Pipeline Company, LLC	Membership Interest	45.72
Tri-Cross Renewable Energy, LLC	Membership Interest	47.50
Van Winkle Digester Renewable Energy, LLC	Membership Interest	47.50
VF Renewable Energy, LLC	Membership Interest	47.50
1560 Broadway, Suite 2090, Denver, Colorado, 80202, United States		
Cedar Creek II, LLC	Membership Interest	50.00
160 Greentree Drive, Suite 101, Dover, County of Kent DE 19904, United States		
Zubie, Inc.	Ordinary B	20.30
16192 Coastal Highway, Sussex County, Lewes, DE, 19958, United States		
Aparecida I Power Holding LLC	Membership Interest	25.00
1675 South State Street, Suite B, Dover, Kent Country, Delaware 19901 US, United States		
SYZYGY PLASMONIC INC	Preference B	50.00
251 Little Falls Drive, Wilmington, DE 19808, United States		
Bass Solar Class B, LLC	Membership Interest	49.97
Bass Solar Construction, LLC	Membership Interest	49.97
Bass Solar Holdings 1, LLC	Membership Interest	49.97
Bass Solar Holdings 2, LLC	Membership Interest	49.97
Bass Solar Holdings, LLC	Membership Interest	49.97
Beacon Wind Holdings LLC	Membership Interest	50.00
Beacon Wind LLC	Membership Interest	50.00
Bellflower Solar 1, LLC	Membership Interest	49.97
Bighorn Solar 1, LLC	Membership Interest	24.99
Bighorn Solar Class B, LLC	Membership Interest	49.97
Bighorn Solar Construction, LLC	Membership Interest	49.97
Bighorn Solar Holdings 1, LLC	Membership Interest	49.97

The parent company financial statements of BP p.l.c. on pages 282-336 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

Bighorn Solar Holdings 2, LLC	Membership Interest	49.97
Bighorn Solar Holdings, LLC	Membership Interest B	24.99
Birch Solar 1, LLC	Membership Interest	49.97
Black Bear Alabama Solar 1, LLC	Membership Interest	25.73
Black Bear Alabama Solar Holdings 1, LLC	Membership Interest	49.97
Black Bear Alabama Solar Holdings 2, LLC	Membership Interest	49.97
Black Bear Alabama Solar Holdings, LLC	Membership Interest	25.73
Black Bear Alabama Solar Land Holdings, LLC	Membership Interest	49.97
Black Bear Alabama Solar Manager, LLC	Membership Interest	49.97
Briar Creek Solar 1, LLC	Membership Interest	49.97
Chester Solar Energy, LLC	Membership Interest	49.97
Continental Divide Solar I, LLC	Membership Interest	49.97
Continental Divide Solar II, LLC	Membership Interest	49.97
Continental Divide Solar Land Holdings, LLC	Membership Interest	49.97
Cottontail Solar 1, LLC	Membership Interest	49.97
Cottontail Solar 10, LLC	Membership Interest	49.97
Cottontail Solar 2, LLC	Membership Interest	49.97
Cottontail Solar 3, LLC	Membership Interest	49.97
Cottontail Solar 4, LLC	Membership Interest	49.97
Cottontail Solar 5, LLC	Membership Interest	49.97
Cottontail Solar 6, LLC	Membership Interest	49.97
Cottontail Solar 7, LLC	Membership Interest	49.97
Cottontail Solar 8, LLC	Membership Interest	49.97
Cottontail Solar 9, LLC	Membership Interest	49.97
Cottontail Solar Class B, LLC	Membership Interest	49.97
Cottontail Solar Construction Holdings, LLC	Membership Interest	49.97
Cottontail Solar Construction, LLC	Membership Interest	49.97
Cottontail Solar Holdings 1, LLC	Membership Interest	49.97
Cottontail Solar Holdings 2, LLC	Membership Interest	49.97
Cottontail Solar Holdings, LLC	Membership Interest	49.97
Crawfish Solar Class B, LLC	Membership Interest	49.97
Crawfish Solar Construction Holdings, LLC	Membership Interest	49.97
Crawfish Solar Construction, LLC	Membership Interest	49.97
Crawfish Solar Holdings 1, LLC	Membership Interest	49.97
Crawfish Solar Holdings 2, LLC	Membership Interest	49.97
Crawfish Solar Holdings, LLC	Membership Interest	49.97
Crawford Solar, LLC	Membership Interest	49.97
Driver Solar, LLC	Membership Interest	49.97
Elk Hill Solar 1 Holdings, LLC	Membership Interest	49.97
Elk Hill Solar 1, LLC	Membership Interest	49.97
Elk Hill Solar 2 Holdings, LLC	Membership Interest	49.97
Elk Hill Solar 2, LLC	Membership Interest	49.97
Elm Branch Solar 1, LLC	Membership Interest	49.97
Empire Offshore Wind Holdings LLC	Membership Interest	50.00
Empire Offshore Wind LLC	Membership Interest	50.00
FreeWire Technologies, Inc.	Membership Interest	22.90
Glade CD Solar Holdings, LLC	Membership Interest	49.97
Glade Solar Class B, LLC	Membership Interest	49.97
Glade Solar Construction Holdings, LLC	Membership Interest	49.97
Glade Solar Construction, LLC	Membership Interest	49.97
Glade Solar Holdings 1, LLC	Membership Interest	49.97
Glade Solar Holdings 2, LLC	Membership Interest	49.97
Glade Solar Holdings, LLC	Membership Interest B	49.97
Glade Solar Land Holdings, LLC	Membership Interest	49.97
Granite Hill Solar LLC	Membership Interest	49.97
Happy Solar 1, LLC	Membership Interest	49.97
Honeysuckle Solar, LLC	Membership Interest	49.97
Impact Solar 1, LLC	Membership Interest	49.97
Impact Solar Class B, LLC	Membership Interest	49.97

The parent company financial statements of BP p.l.c. on pages 282-336 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

Impact Solar Construction, LLC	Membership Interest	49.97
Impact Solar Holdings 1, LLC	Membership Interest	49.97
Impact Solar Holdings 2, LLC	Membership Interest	49.97
Impact Solar Holdings, LLC	Membership Interest B	49.97
Jones City Solar II, LLC	Membership Interest	49.97
Jones City Solar, LLC	Membership Interest	49.97
Lightsource Beacon 2, LLC	Membership Interest	49.97
Lightsource Beacon Holdings, LLC	Membership Interest	49.97
Lightsource Beacon, LLC	Membership Interest	49.97
Lightsource Renewable Energy Asset Holdings 1, LLC	Membership Interest	49.97
Lightsource Renewable Energy Asset Management Holdings, LLC	Membership Interest	49.97
Lightsource Renewable Energy Asset Management, LLC	Membership Interest	49.97
Lightsource Renewable Energy Assets Holdings, LLC	Membership Interest	49.97
Lightsource Renewable Energy Austin Holdings, LLC	Membership Interest	49.97
Lightsource Renewable Energy Services Holdings, LLC	Membership Interest	49.97
Lightsource Renewable Energy Services, Inc.	Ordinary	49.97
Lightsource Renewable Energy Trading, LLC	Membership Interest	49.97
Maverick Solar Class B, LLC	Membership Interest	49.97
Maverick Solar Construction, LLC	Membership Interest	49.97
Maverick Solar Holdings 1, LLC	Membership Interest	49.97
Maverick Solar Holdings 2, LLC	Membership Interest	49.97
Maverick Solar Holdings, LLC	Membership Interest	49.97
Paper Shell Solar 1, LLC	Membership Interest	49.97
Pine Burr Solar 1, LLC	Membership Interest	49.97
Poplar Solar 1, LLC	Membership Interest	49.97
South Shelby RNG, LLC	Membership Interest	50.00
Sun Mountain Solar 1, LLC	Membership Interest	49.97
TX Gulf Solar 1 LLC	Membership Interest	49.97
Ventress Solar Farm 1, LLC	Membership Interest	49.97
Ventress Solar Land Holdings, LLC	Membership Interest	49.97
White Trillium Solar, LLC	Membership Interest	49.97
Whitetail Solar 1, LLC	Membership Interest	49.97
Whitetail Solar 2, LLC	Membership Interest	49.97
Whitetail Solar 3, LLC	Membership Interest	49.97
Whitetail Solar 6, LLC	Membership Interest	49.97
Whitetail Solar Land Holdings, LLC	Membership Interest	49.97
Wildflower Solar I, LLC	Membership Interest	49.97
Wildflower Solar Land Holdings, LLC	Membership Interest	49.97
2711 Centerville Road, Suite 400, Wilmington DE 19808, United States		
Energy Emerging Investments, LLC	Membership Interest	50.00
30600 Telegraph Road, Suite 2345, Bingham Farms MI 48025, United States		
Canton Renewables, LLC	Membership Interest	50.00
4001 Kennet Pike, Suite 302, Wilmington, DE, 19807, United States		
AEP I HoldCo LLC	Membership Interest	24.30
6400 Shafer Ct., Suite 400, IL 60018-4927, Rosemont, United States		
Cantera K-3 Limited Partnership	Partnership interest	39.00
800 S. Gay Street, Suite 2021, Knoxville TN 37929, United States		
CERF Shelby, LLC	Membership Interest	50.00
815, 14th Street SW, Suite A100, Loveland, CO 80537, United States		
Lightning eMotors, Inc.	Ordinary	30.60
850 New Burton Road, Suite 201, Dover, Delaware, 19902, United States		
Johnson Corner Solar I, LLC	Membership Interest	49.97
Lightsource Renewable Energy Development, LLC	Membership Interest	49.97
Lightsource Renewable Energy Management, LLC	Membership Interest	49.97
Lightsource Renewable Energy Operations, LLC	Membership Interest	49.97
Lightsource Renewable Energy US, LLC	Membership Interest	49.97
LSBP NE Development, LLC	Membership Interest	49.97
SeaPort Midstream Partners, LLC	Membership Interest	49.00
Zippity, Inc.	Preference	22.60

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14. Related undertakings of the group – continued

920 North King Street, 2nd Floor, Wilmington DE 19801, United States		
Atlantic 1 Holdings LLC	Membership Interest	34.00
Atlantic 2/3 Holdings LLC	Membership Interest	42.50
Atlantic 4 Holdings LLC	Membership Interest	37.78
Uruguay		
Avenida Luis Alberto de Herrera 1248, Oficina 1901, Montevideo, Uruguay		
Axuy Energy Holdings S.R.L.	Membership Interest	50.00
Axuy Energy Investments S.R.L.	Membership Interest	50.00
Colonia 810, Oficina 403, Montevideo, Uruguay		
Baplor S.A.	Ordinary	50.00
Gemalsur S.A.	Ordinary	50.00
Pan American Energy Holdings S.A.	Ordinary	50.00
Pan American Energy Uruguay S.A.	Ordinary	50.00
La Cumparsita 1373, piso 4°, Montevideo, Uruguay		
Dinarel S.A.	Ordinary	20.00
Luis A de Herrera 1248, Torre II, Piso 22 (Edificio World Trade Center), Montevideo, Uruguay		
Axion Comercializacion De Combustibles Y Lubricantes S.A.	Ordinary	50.00
Zimbabwe		
Block 1 Tendeseka Office Park, Samora Machel Av/Renfrew Road, Harare, Zimbabwe		
Central African Petroleum Refineries (Pvt) Ltd	Membership Interest	20.75

[a] 1% interest held directly by BP p.l.c.
[b] 100% interest held directly by BP p.l.c.
[c] 0.01% interest held directly by BP p.l.c.
[d] 99% interest held directly by BP p.l.c.
[e] 50% interest held directly by BP p.l.c.
[f] 15% interest held directly by BP p.l.c.
[g] 5% interest held directly by BP p.l.c.
[h] See Note 37 Events after the reporting period in the group financial statements.

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