

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 plc (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 2022 and of the group's loss 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) as issued by the International Accounting Standards Board (IASB) and as adopted by the European Union (EU).
- The parent company financial statements have been properly prepared in accordance with United Kingdom accounting standards (United Kingdom generally accepted accounting practice), including FRS 101 'Reduced Disclosure Framework'.
- The financial statements have been prepared in accordance with the requirements of the Companies Act 2006.

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 13 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 and as adopted by the EU. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom accounting standards, including FRS 101 'Reduced Disclosure Framework' (United Kingdom generally accepted accounting practice).

2. Basis for opinion

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

We are independent of the group and the parent company in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the Financial Reporting Council's (the 'FRC's') Ethical Standard as applied to listed public interest entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements. The non-audit services provided to the group and parent company for the year are disclosed in Note 36 to the financial statements. We confirm that we have not provided any non-audit services prohibited by the FRC's Ethical Standard to the group or the parent company.

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

3. Summary of our audit approach

Key audit matters	<p>The key audit matters that we identified in the current year were:</p> <ul style="list-style-type: none"> • 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. <p>All key audit matters are consistent with those we identified in the prior year and the developments in fact patterns of these previously identified key audit matters are explained in respective sections below.</p>
Materiality	<p>The materiality that we used for the group financial statements was \$1,250 million (2021 \$700 million) which was determined based on profit before tax adjusted for the exceptional charges of \$25.5 billion (comprising mainly of investment impairment and recycling of accumulated exchange losses from equity) associated with the decision to exit bp's shareholding in Rosneft and underlying replacement cost profit before interest and tax.</p> <p>In the prior year we determined materiality using profit before tax (with no adjustments) and underlying replacement cost profit before interest and tax.</p>
Scoping	<p>Our scope covered 204 consolidation units (cons units). Of these, 152 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 71% of group revenue, 77% of PP&E and 71% of profit before tax. The remaining 717 cons units were subject to other procedures, including performing analytical reviews, making inquiries and evaluating and testing management's group-wide controls.</p>

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 the nature of the facilities, repayment terms and covenants
- assessing whether the impact of potential margin calls in respect of derivative exchange contracts used to risk manage the physical portfolio have been appropriately considered given price volatility
- 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
- assessing 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 year 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.

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, investments in joint ventures and provisions)

Key audit matter description	
	<p>Climate change impacts bp's business in a number of ways as set out in the strategic report on pages 1 to 76 of the Annual Report and Note 1 of the financial statements on page 185. It represents a strategic challenge and a key focus of management. The related risks that we have identified for our audit are as follows:</p> <ul style="list-style-type: none"> • Forecast assumptions used in assessing the value-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, there is an exposure to decommissioning obligations that may revert back to bp in respect of assets transferred to third parties through historical divestments. The risk of exposure is enhanced due to the impacts of climate change which have heightened long term financial resilience concerns for many industry participants. Furthermore, provisions for decommissioning refining assets, 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 \$4.2 billion total exploration and appraisal (E&A) assets capitalised as at 31 December 2022 (2021 \$4.3 billion) are potentially exposed to climate change and the global energy transition risk factors (see Note 15). This is because a greater number of E&A projects may not proceed as a consequence of the energy transition leading to lower forecast future oil and gas prices, bp's intention to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 – see page 186) 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 and continues to require significant management judgement. • The carrying value of bp'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 certain refineries during the year. As a result, impairment tests were performed to assess the recoverability of the refineries' carrying values. As disclosed in Note 4 to the accounts on page 208, management has recorded an impairment charge of \$1,366 million in respect of the Gelsenkirchen refinery in Germany, driven by changes in economic assumptions. • bp's intention to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 – see page 186) and the group's wider strategy includes potentially disposing of certain higher emissions intensity upstream oil assets and others. As a consequence, for certain assets and investments 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 \$2.9 billion (2021 \$1.1 billion) of pre-tax impairment charges in 2022 for such potential disposals as described in Note 4. There is a 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 carrying value of the group's investments in low carbon energy assets may no longer be recoverable due to an increase in the low carbon energy discount rate, project development costs increasing as a result of higher inflation and the impact that the increased activity within the sector, as a result of the energy transition, has had on the demand for low carbon energy supply chain goods and services. • 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. Of the total refining assets carried in the balance sheet, all but an immaterial residual value relating primarily to land and buildings, will be fully depreciated by 2050. As disclosed in Note 1 to the accounts on page 186, 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.

	<ul style="list-style-type: none"> The total goodwill balance as at 31 December 2022 is \$12.4 billion, of which \$7.2 billion relates to upstream oil and gas assets. The carrying values of goodwill may no longer be recoverable as a consequence of climate change 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 significant level of headroom in the goodwill impairment tests, management identified no other assumption that could lead to a material misstatement of goodwill due to the energy transition and other climate change factors. Disclosures in relation to sensitivities for goodwill are included within Note 14 on page 221. The C&P segment has a goodwill balance of \$4.7 billion, of which the most significant element is \$2.5 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 14), 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 33 to the financial statements, may lead to an outflow of funds requiring provision. <p>The above considerations were a significant focus of management during the period which led to this being a matter that we communicated to the audit committee, and which had a significant effect on the overall audit strategy. We therefore identified this as a key audit matter.</p>
<p>How the scope of our audit responded to the key audit matter</p>	<p>Overall response</p> <p>We held discussions with management, with our 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.</p> <p>We also continued to utilise 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.</p> <p>Audit procedures</p> <p>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 157-159 and 'Decommissioning provisions' on pages 160-161. Other procedures are as follows:</p> <p>In respect of the recoverability of E&A assets capitalised as at 31 December 2022:</p> <ul style="list-style-type: none"> We obtained an understanding of the group's E&A write-off and impairment assessment processes and tested relevant internal controls, which specifically consider 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 judgements with 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, reading meeting minutes and reviewing licence documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms. We 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 and bp's intention to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 – see page 186). <p>We have considered the impact of potential changes in supply and demand on the group's refining portfolio and reviewed internal and external market studies of future supply and demand. In relation to the Gelsenkirchen refinery impairment test, we assessed the valuation methodology, tested the integrity and mechanical accuracy of the impairment model and assessed the appropriateness of key assumptions and inputs, notably forecast refining margins and energy input costs, challenging and evaluating management's assumptions by reference to third party data where available. 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 test and related inputs.</p> <p>We challenged management's analysis that identified the specific assets that are likely to be disposed of by bp 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, carefully considered bp's strategic intent in this context and challenged management's assessment of the recoverable amounts for material transactions. We also tested relevant controls which covered both the recoverable amounts determined and the likelihood of transaction completion.</p> <p>In respect of the impairment tests performed on certain low carbon energy investments, we tested the result by:</p> <ul style="list-style-type: none"> Testing the relevant controls over low carbon energy impairment tests including controls over key assumptions and the discount rate Assessing the low carbon energy discount rate with input from our valuation specialists

- Challenging and evaluating the key assumptions within the impairment tests, which included capital and operating cost assumptions, forecast yield and power price assumptions, debt and interest assumptions, and the applicability of the Inflation Reduction Act legislation on investment credit assumptions and
- Testing the mechanical accuracy of the impairment models.

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 2022 which shows that demand for refined petroleum products is expected to remain sufficient for at least the current remaining useful economic lives of the refineries such that current depreciation rates are appropriate, including under the Announced Pledges Scenario which is associated with a temperature rise of 1.7 °C in 2100 (with a 50% probability).

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 group general counsel and other senior bp lawyers regarding climate change matters
- Conducting a search for climate change litigation and claims brought against the group
- Making written inquiries of, and holding discussions with, external legal counsel advising bp in relation to climate change litigation and
- Reviewing the contingent liability disclosures in the annual report on pages 257-259.

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 the low carbon energy impairment tests, noting that the investment valuations remain sensitive in particular to capital and operating cost assumptions, the ability to secure project financing at the interest rates assumed, and for certain projects the pricing that can be secured under future power purchase contracts. The discount rate used by management was lower than we would have expected but this did not impact the outcome of the tests
- 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 45. 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 six years and the refining assets (within the C&P segment) is thirteen years.

5.2 Impairment of upstream oil and gas property, plant and equipment (PP&E) assets

Key audit matter description	
	<p>The group balance sheet as at 31 December 2022 includes PP&E of \$106 billion (2021 \$113 billion), of which \$76 billion (2021 \$74 billion) is oil and gas properties within the OP&O (\$48 billion) and G&LCE (\$28 billion) segments.</p> <p>Management's oil and gas price assumptions for value-in-use impairment tests were revised in 2022 as set out in Note 1 on page 192. Brent oil price assumptions were increased in the short and medium term, reflecting management's expectation of supply constraints over the next decade due to restrictions on Russian exports, although there has been no significant change to longer term Brent oil forecasts reflecting bp's unchanged view on the longer term speed of the low carbon energy transition. Henry Hub gas price assumptions have increased until 2050, reflecting a view that US domestic gas production will need to grow, in large part to offset the loss of Russian gas exports.</p> <p>Management has also revised bp's 'best estimate' discount rate assumptions for value-in-use impairment tests in 2022, as set out in Note 1 on page 192. bp's post-tax nominal weighted average cost of capital, being the starting point for setting discount rates used for impairment testing for oil and gas assets, has increased to 7% (2021 6%), reflecting the impact of observable increases in risk free rates on bp's weighted average cost of capital.</p> <p>Given the significance of the price and discount rate assumption revisions during 2022, alongside certain CGU specific new indicators, management has tested all oil and gas CGUs for impairment and/or impairment reversal during the year. Management recorded \$2.2 billion (2021 \$4.8 billion) of pre-tax oil and gas CGU impairment reversals, principally due to the oil and gas price upward revisions detailed above, and \$5.2 billion of pre-tax oil and gas CGU impairment charges (2021 \$2.4 billion) due principally to increased expenditure forecasts and the increased discount rate. Further information has been provided in Note 1 on page 192 and Note 4 on page 207.</p> <p>We identified three key management estimates in management's determination of the level of impairment charge and/or impairment reversal. These are:</p> <p>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, macro-economic factors and disruption in global supply due to the Russian-Ukraine war. There is a risk that management do not forecast reasonable 'best estimate' oil and gas price forecasts when assessing CGUs for impairment charge and/or impairment 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.</p> <p>Aside from 2023 where oil and gas prices reflect near-term expected market conditions, bp'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.</p> <p>As described in Note 1 on page 185, 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. Management's judgement is that the potential impact of such further emissions costs being borne by producers including bp is not expected to have a material impact on bp's oil and gas CGU carrying values as costs would effectively be borne by oil and gas end users via overall higher commodity prices. There is a risk that management's judgement is not reasonable.</p> <p>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 does 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.</p> <p>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 proven and/or probable reserves estimates, that are inherently less certain than reserves; and assumptions related to these volumes can be particularly judgmental. 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.</p> <p>We identified certain individual CGUs with a total carrying value of \$17 billion (2021 \$33 billion) which we determined would be most at risk of material impairment charges as a result of a reasonably possible change in the oil and gas price assumptions. This population includes \$4 billion of previously impaired assets which are also at risk of material impairment reversal resulting from potential oil and gas price assumption changes. 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.</p> <p>We also identified CGUs with a further \$13 billion (2021 \$12 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 reasonably possible 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 193.</p>

	<p>Impairment charge and/or impairment 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.</p>
<p>How the scope of our audit responded to the key audit matter</p>	<p>We tested relevant 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 charge and/or impairment reversal assessments where we identified audit risks. In addition, we conducted the following substantive procedures.</p> <p>Oil and gas prices</p> <ul style="list-style-type: none"> • We independently developed a reasonable range of forecasts based on external data obtained, against which we compared 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 Conference of the Parties (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 27 in Cairo during November 2022. 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 evaluated whether they presented contradictory audit evidence. • We challenged management’s judgement, described in Note 1 on page 185, that the potential impact of further emission costs being borne by producers including bp is not expected to have a material impact on bp’s oil and gas CGU carrying values. We inquired of certain third party forecasters included in our reasonable range and read 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 4, 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 bp’s value-in-use estimates for oil and gas CGUs. <p>Discount rates</p> <ul style="list-style-type: none"> • We independently evaluated bp’s discount rates used in impairment tests with input from our 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 and evaluated management’s disclosures in Notes 1 and 4 including in relation to the sensitivity of discount rate assumptions. <p>Reserves and resources estimates</p> <ul style="list-style-type: none"> • With the assistance of our oil and gas reserves specialists we: assessed bp’s reserves and resources estimation methods and policies • assessed 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, capabilities 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 and • performed a retrospective assessment to check for indications of estimation bias over time. <p>Other procedures</p> <ul style="list-style-type: none"> • We challenged and assessed management’s CGU determinations, including the evaluation of contradictory evidence. • We assessed whether bp’s impairment methodology was acceptable under IFRS and tested the integrity and mechanical accuracy of certain impairment models. • For certain CGUs we challenged and assessed 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 production forecasts are consistent overall with bp’s strategy, including the group’s expectation to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 - see page 186). • 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.

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

Key observations	<p>Oil and gas prices</p> <p>For the purpose of PP&E impairment tests, management is required under IAS 36 to apply its current 'best estimate' of future oil and gas prices. 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.</p> <p>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 from April 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.</p> <p>Management notes on page 185 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 Brent price assumptions were overall within the higher half of our range of Paris 'well below 2°C goal' and '1.5°C ambition' scenarios. This is consistent with bp's prior period positioning within our Brent oil range. For Henry Hub gas, management's decision to adopt higher gas price assumptions until 2050 has moved bp's best estimate into the top half of our 'best estimate' range in the short and medium term, before settling towards the middle of our range in the longer term. The gas price assumptions are close to the top of our range of Paris 'well below 2°C goal' and '1.5°C ambition' scenarios in the short and medium term and remain in the top half in the longer term. This reflects an increase compared to the prior period, when bp's gas price assumptions were in the lower half of our 'best estimate' range and towards the midpoint of our range of Paris 'well below 2°C goal' and '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 '1.5°C ambition' scenarios, highlighting the large inherent uncertainty regarding 'Paris consistent' pathways and the very wide range of potential price forecasts. Accordingly, we consider management's statement as set out above to be reasonable.</p> <p>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.</p> <p>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 lower than the 'best estimate' in all future periods, is broadly in the middle of our range of third party Paris 'well below 2°C goal' and Paris '1.5°C ambition' scenarios between 2025 and 2030 and thereafter close to the bottom of the range for both Brent oil and Henry Hub gas.</p> <p>Discount rates</p> <p>bp's post-tax nominal 7% 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 valuation specialists.</p> <p>We were also satisfied with the calculation of country risk premia. Accordingly, we are satisfied with the discount rates used in the impairment charge and impairment reversal testing.</p> <p>Reserves and resources</p> <p>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 charge and impairment reversal tests.</p> <p>Other procedures</p> <p>We observed that management's production forecasts are not consistent in aggregate with bp's strategy because bp expects to dispose of certain non-core assets in future periods (see 'Potential impact of climate change and the energy transition' above and page 55 of Annual Report).</p>
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5.3 Decommissioning provisions

<p>Key audit matter description</p>	<p>A decommissioning provision of \$12.3 billion is recorded in the financial statements as at 31 December 2022 (2021 \$16.4 billion). 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, in particular inflation and discount rate assumptions. Given management expects hydrocarbon production to be around 25% lower by 2030 relative to 2019 as stated on page 186, consistency of that expectation with the timing of decommissioning expenditure and underlying cost assumptions remains a key consideration.</p> <p>Due to sustained levels of high global inflation, particularly in key geographies such as the U.S. and U.K., where a majority of bp's future decommissioning cost obligations are located, the impact of inflation on bp's decommissioning provision represents an area of particular risk. Consistent with prior years, management estimates that the average rate of forecast inflation applicable to the substantial majority of bp's decommissioning cost estimates is 1.5%, which is 0.5% lower than its estimated long term general inflation rate of 2%. The extent to which average future decommissioning cost inflation will differ from the general inflation rate depends on industry demand and supply of rigs and other relevant services at the time future decommissioning occurs, which in turn will be influenced by future oil and gas demand, and increasingly by structural changes in the industry supply chain driven by the energy transition, which are uncertain. As a result, the decommissioning inflation rate assumption is particularly judgemental and we have identified a significant risk of material misstatement in relation to this judgement.</p> <p>The estimated undiscounted cost of its obligations and the timing of future payment are set out in Note 1 on page 199. 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.</p> <p>bp increased its discount rate used in calculating its decommissioning provisions from 2.0% as at 31 December 2021 to 3.5% as at 31 December 2022. The increase was primarily driven by the increased US treasury bond rates.</p> <p>Additionally, bp is 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 reversion could be elevated by the potential impact of the energy transition, in particular the potential for lower oil and gas prices in the longer term which could result in financial resilience concerns for some industry participants. The risk further increased following a US legal judgement in 2020 which required a specific provision and increased the likelihood of decommissioning liabilities reverting to former owners as part of a bankruptcy proceeding.</p> <p>Provisions for decommissioning refining assets, 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 199 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. 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.</p>
<p>How the scope of our audit responded to the key audit matter</p>	<p>We obtained an understanding of the group's decommissioning estimate and provisioning process and evaluated the effectiveness of the relevant controls.</p> <p>Long term inflation rate</p> <ul style="list-style-type: none"> • We tested the control related to the determination of the decommissioning specific inflation rate assumption. • We tested how management derived the decommissioning specific inflation rate assumption of 1.5%, and the evidence on which it is based, by gaining an understanding of the process used by management, testing management's calculations of the assumption, and evaluating the evidence relevant to management's assumption, both supporting and contradictory. • As the 1.5% decommissioning specific inflation rate assumption is determined by making an adjustment to management's 2.0% general long term inflation rate assumption, we evaluated, with the help of our valuation specialists, the general long term inflation rate assumption used of 2.0%, comparing it against latest external market data. • We made inquiries with, and evaluated the competence, capabilities and objectivity, of management's decommissioning experts who derived the decommissioning specific inflation rate. • We inspected analyst forecasts and reports in respect of the future decommissioning market and related costs for evidence of supporting and contradictory evidence, with particular focus on the future rig market. • We particularly 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 market and related inflation assumption. • We analysed historical trends of rig market rates against oil prices and historical inflation to challenge management's assumption that the decommissioning inflation assumption does not inflate at the same rate as general inflation.

	<p>Cost and timing estimates</p> <ul style="list-style-type: none"> We tested the controls over the year end decommissioning cost and timing assumptions used within management's decommissioning provision estimate. 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 challenged whether the impact of inflation experienced in 2022 was appropriately considered and reflected where relevant within bp's cost assumptions, and also assessed the reasonableness of key cost assumptions with reference to internal and appropriate third party data. 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. <p>Discount rates</p> <ul style="list-style-type: none"> We tested the control related to the determination of the discount rate assumption. With the help of our valuation specialists, we evaluated the discount rate assumption used, comparing it against latest external market data. <p>Reversion risk</p> <ul style="list-style-type: none"> We obtained an understanding of bp's decommissioning reversion risk assessment process and tested relevant internal controls including those controls over the completeness and accuracy of the previously divested asset data. We challenged and evaluated management's key judgements related to the decommissioning reversion risk and conclusions as to 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. <p>Potential decommissioning of refinery assets</p> <ul style="list-style-type: none"> We challenged and evaluated management's analysis which supported the 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. We have reviewed analysis undertaken by management, as well as third party studies, of forecast demand for refined products in regions served by bp's refineries. Furthermore, we read external profitability benchmarking which supported a conclusion that the group'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 and obtained evidence that management is developing plans for the existing refinery sites remaining in the portfolio which would be compatible with net zero emissions, for instance through the production of alternative low carbon and sustainable fuels. <p>We tested the decommissioning models, assessing the application of cost, timing, inflation and discount rate assumptions.</p>
<p>Key observations</p>	<p>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 2022 does not require a change to bp's long term average inflation assumption. With respect to the extent to which average future decommissioning cost inflation will differ from the general inflation rate, which is influenced by the demand and supply of rigs and other relevant services at the time future decommissioning occurs, we concluded that market forecasts support the assertion that demand for rigs will not increase in the long term as a result of the impact of the energy transition and therefore that inflation of rig costs will be limited.</p> <p>We concluded 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 199 with respect to the estimated undiscounted cost of bp's decommissioning obligations and the timing of future decommissioning payments are consistent with these conclusions.</p> <p>bp's increased 3.5% discount rate was within a reasonable range based on latest market data.</p> <p>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 potential 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.</p> <p>In respect of the group's refining assets, taking into consideration both the IEA 2022 demand forecasts and management's strategic plans for the group's refineries, including developing 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.</p>

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	<p>In the normal course of business, T&S enters into a variety of transactions for delivering value across the group's supply chain. In pursuit of achieving bp's 'net zero' ambition and to support the overall group strategy, T&S as a function is increasingly focused on securing long term renewable power offtake/supply contracts in existing and new markets whilst providing solutions to bp's customers through offering eco-friendly hydrocarbons. Given the nature of these transactions, we direct significant audit effort towards challenging management's adopted accounting treatment and/or valuation estimates.</p> <p>Throughout the year, we have kept our risk assessment updated by undertaking an iterative review of the underlying portfolio composition. This process facilitated a deeper understanding of the impact of commodity price volatility, demand destruction and the changing structure of the markets resulting from supply dislocations due to the Russian-Ukraine war allowing us to focus our audit effort to areas of highest risk.</p> <p>Accounting for structured commodity transactions (SCTs):</p> <p>T&S may also enter into a variety of transactions which we refer to as structured commodity transactions (SCTs). We generally refer to the following factors to identify a SCT:</p> <ul style="list-style-type: none">• two or more counterparties with non-standard contractual terms;• reference multiple commodity-based transactions; or• contractual arrangements entered into in contemplation of each other. <p>SCTs are often long-dated, can have a significant multi-year financial impact, and may require the use of complex valuation models or unobservable inputs when determining their fair value, in which case they will be classified as level 3 financial instruments under IFRS 13, 'Fair Value Measurement'.</p> <p>Accounting for SCTs is 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 \$487 million or higher on balances that affect group KPIs.</p> <p>Although we have assessed new SCTs entered into during the year, we have not identified any new types of SCT transactions which we assess to be a significant risk.</p> <p>Valuation of commodity derivatives:</p> <p>Commodity markets remained volatile during the year on the back of continuing demand uncertainty as a result of the global energy transition, macro-economic factors and disruptions in global supply due to the Russian-Ukraine war. In response to the volatility observed, we focused our audit efforts on the valuation of all commodity derivatives and designed procedures specifically to test for management bias.</p> <p>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.</p> <p>As at 31 December 2022, the group's total derivative financial assets and liabilities measured at fair value were \$24.4 billion (2021 \$12.8 billion) and \$26.2 billion (2021 \$13.9 billion), of which level 3 derivative financial assets were \$8.8 billion (2021 \$5.5 billion) and level 3 derivative financial liabilities were \$7.0 billion (2021 \$3.9 billion).</p>
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<p>How the scope of our audit responded to the key audit matter</p>	<p>Accounting for structured commodity transactions:</p> <p>For structured commodity transactions, we:</p> <ul style="list-style-type: none"> • 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 offtake arrangements and/or significant contractual commitments. • Selected a sample of existing working capital arrangements and financing structures to assess whether associated trading activity was in compliance with pre-determined boundary conditions and whether the conclusions reached remained in compliance with relevant accounting standards. <p>For SCTs which were identified during the prior years and that continue through 2022, we have refreshed our assessment in 2022 taking account of any amendments to the contracts. We assessed whether the conclusions reached previously remain appropriate and in accordance with relevant accounting standards.</p> <p>To assess the appropriateness of the accounting treatment of SCTs, we embedded technical accounting specialists within the audit team.</p> <p>Valuation of commodity derivatives:</p> <p>In response to the continuing high 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 derivatives at 30 June and of distinct samples of both Level 2 and Level 3 derivatives at 30 September and 31 December. In addition, we focused our testing on price inputs where bp has substantial exposure to illiquid (Level 3) or long dated (Level 2) curves.</p> <p>To address the complexities associated with auditing the value of level 3 financial instruments, the engagement team included valuation specialists having significant quantitative and modelling expertise to assist in performing our audit procedures. Our valuation audit included the following control and substantive procedures:</p> <ul style="list-style-type: none"> • We tested the group's valuation controls including the: <ul style="list-style-type: none"> – 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: <ul style="list-style-type: none"> – 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 our valuation specialists to challenge models, develop fair value estimates and evaluate 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.
<p>Key observations</p>	<p>We assessed the features of the SCTs and determined that the accounting adopted for each of them was appropriate and in accordance with IFRS.</p> <p>We concluded that management's valuations relating to commodity derivatives were appropriate.</p> <p>We did not identify any indications of inappropriate misrepresentation of revenue recognition in the transactions, valuation estimates or accounting entries that we tested.</p> <p>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.</p>

5.5 IT controls relating to financial systems

Key audit matter description	<p>The group's financial systems environment is complex, with 119 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.</p> <p>User Access Management:</p> <p>From 2018 to 2021 we identified a number of deficiencies relating to user access management across the group's IT environment (together 'access deficiencies'). Management implemented a remediation programme and as at 31 December 2021, the remaining deficiencies related to the implementation and sustainability of controls specifically over the review and control of IT privileged access. In 2022, management redesigned these controls but the new controls were not in operation for the entire year and therefore management continued to operate mitigating controls. See the Audit Committee Report on page 104.</p> <p>Access deficiencies 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.</p> <p>The above considerations continued to be a significant focus of management during the period which led to this being a matter that we communicated to the audit committee, and which had a significant effect on the overall audit strategy. We therefore identified this as a key audit matter.</p>
How the scope of our audit responded to the key audit matter	<p>We obtained an understanding of management's processes and relevant financial systems, and tested the associated general IT controls and automated business controls. We also tested the integrity of key reports. In responding to the identified access deficiencies our IT specialists performed procedures to:</p> <ul style="list-style-type: none"> • test the controls that management has implemented or re-designed in order to remediate the deficiencies • assess and test the mitigating controls that management identified, including directly testing those controls operated by IT service 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 and performed additional mitigating procedures independently.
Key observations	<p>For the period the controls were ineffective, management identified and operated appropriate mitigating controls and our testing confirmed that they operated effectively. In addition, our independent testing did not identify any instances of inappropriate access being exploited.</p> <p>Accordingly, we continued to adopt an audit approach which places reliance on the operating effectiveness of financial controls. Under our methodology, this enables us to apply lower sample sizes in our substantive testing.</p>

5.6 Management override of controls (potentially impacting all financial statement accounts)

Key audit matter description	<p>We conducted an assessment of the fraud risks arising from management override of controls by considering potential areas where the group's financial statements could be manipulated. 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.</p> <p>Our considerations included the potential for:</p> <ul style="list-style-type: none"> • 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. <p>Management has implemented a number of new journal controls in 2021 and 2022 to address deficiencies identified during prior period audits. During the year we identified deficiencies in these new controls but mitigating controls to address the risk associated with the deficiencies were identified. These included low-level analytical reviews, controls over closing balances, period-end analytical review controls and certain automated business controls.</p> <p>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.</p>
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<p>How the scope of our audit responded to the key audit matter</p>	<p>We tested the mitigating controls to respond to the risk of fraudulent journal entries. In addition, we:</p> <ul style="list-style-type: none"> • made inquiries of individuals involved in the financial reporting process about inappropriate or unusual activity relating to the processing of journal entries and other adjustments • identified and tested relevant entity-level controls, in particular those related to the bp Code of Conduct, whistleblowing (bp OpenTalk) and controls monitoring financial reporting processes and financial results • used our data analytics tools to select 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 <p>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:</p> <ul style="list-style-type: none"> • evaluating whether the judgements and decisions made by management in making the accounting estimates included in the financial statements, even if they are individually reasonable, indicate a possible bias on the part of bp's management that may represent a risk of material misstatement due to fraud; and • performing a retrospective analysis of management judgements and assumptions related to significant accounting estimates reflected in the financial statements of the prior year. <p>We considered whether there were any significant transactions that are outside the normal course of business, or that otherwise appear to be unusual due to their nature, timing or size.</p> <p>The risks and responses to the revenue recognition risks within the trading and shipping function are set out on pages 162-163.</p>
<p>Key observations</p>	<p>Our testing of the mitigating controls indicated that they were operating effectively.</p> <p>Our substantive testing of journal entries and other adjustments, selected through the use of our data analytics tools, did not identify any inappropriate items.</p> <p>We did not identify evidence of overall bias or any significant unusual transactions for which the business rationale (or the lack thereof) of the transaction suggested that it may have been entered into to engage in fraudulent financial reporting or to conceal misappropriation of assets.</p>

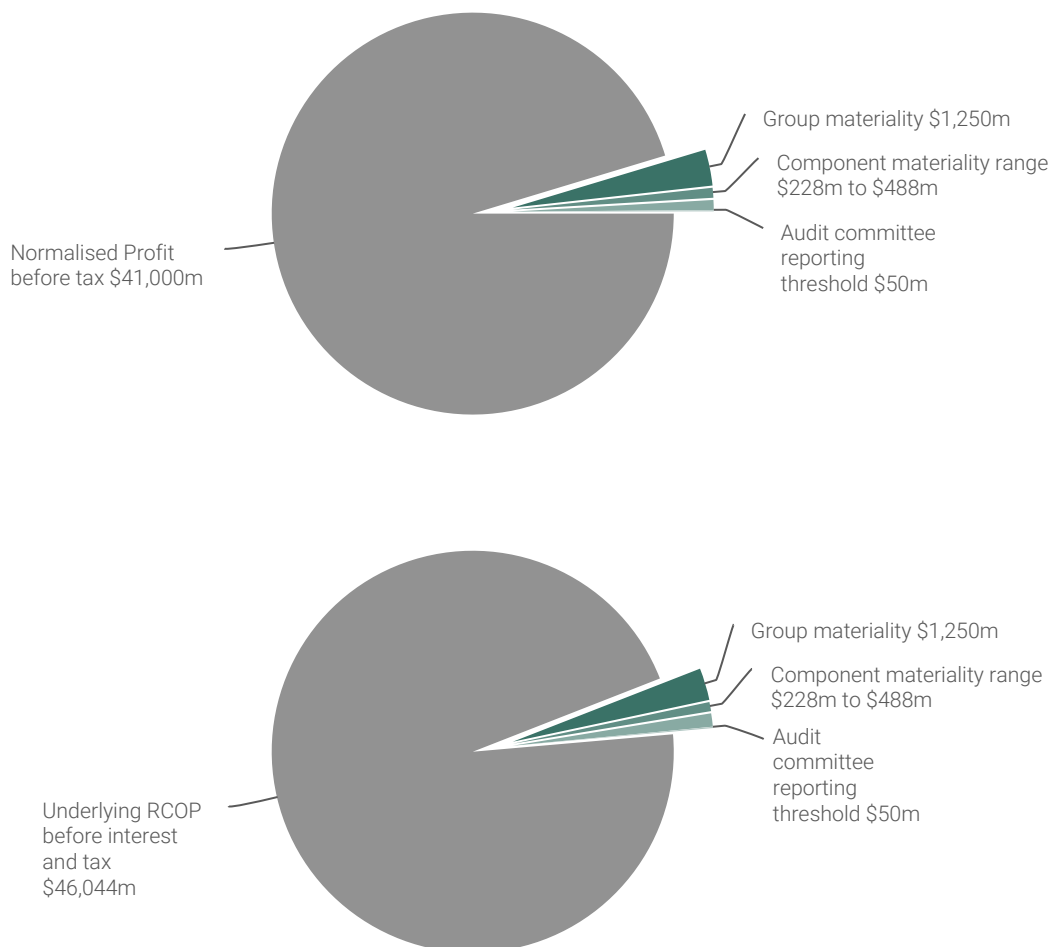
6. Our application of materiality

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	<p>We set materiality for both the group and parent company at \$1,250 million. Group and parent company planning materiality for the current year was set at \$1,000 million and our audit scoping and all the audit testing performed by our component teams was conducted using this planning materiality.</p> <p>In 2021, we used a materiality of \$700 million and \$1,000 million for the group financial statements and the parent company financial statements respectively. The increase in materiality is due to the significant increase in the profitability of the group.</p>	
Basis for determining materiality	<p>Consistent with the prior year we concluded that it is appropriate to use profit before tax as a materiality benchmark; however profit before tax was adjusted for the exceptional charges of \$25.5 billion (comprising mainly of investment impairment and recycling of accumulated exchange losses from equity) associated with the decision to exit BP's shareholding in Rosneft.</p> <p>We also continue to use underlying replacement cost profit before interest and tax as a benchmark for determining materiality.</p> <p>Materiality was determined to be \$1,250 million, which is 3.1% of normalized profit before tax and 2.7% of underlying replacement cost profit before tax.</p> <p>In 2021, we determined materiality to be \$700 million, which represented 4.6% of profit before tax and 3.1% of underlying replacement cost profit before tax.</p>	<p>We determined materiality for our audit of the standalone parent using 1.1% (2021 1%) of net assets.</p>
Rationale for the benchmark applied	<p>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.</p> <p>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.</p> <p>This resulted in us selecting profit before tax and underlying replacement cost profit 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.</p> <p>As noted above, in the basis for determining materiality section, given the nature and size of Russian exit charges we have normalised profit before tax for these charges.</p>	<p>The materiality determined for the standalone parent company is based on net assets as the company is non-trading and operates primarily as a holding company; we believe the net asset position is the most appropriate benchmark to use.</p> <p>Whilst, in accordance with our benchmarks we could have set parent company materiality higher we decided to align it with group materiality of \$1,250 million.</p>



*Normalized profit before tax of \$41 billion is derived as PBT of \$15.4 billion adjusted for the exceptional charges of \$25.6 billion associated with the decision to exit bp's shareholding in Rosneft.

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 and parent company performance materiality was set at 65% of planning materiality for the 2022 audit (2021 65% of materiality).	
Basis and rationale for determining performance materiality	Consistent with the prior year performance materiality of 65% reflects the overall quality of the control environment, the magnitude of misstatements identified in the current and prior years, as well as the fact that management is generally willing to correct any such 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 \$50 million (2021 \$35 million), as well as differences below that threshold that, in our view, warranted reporting on qualitative grounds. We also report to the audit committee on disclosure matters that we identified when assessing the overall presentation of the financial statements.

7. An overview of the scope of our audit

7.1 Identification and scoping of components

As a result of the highly disaggregated nature of the group, with operations in over 60 countries through approximately 920 cons units, a significant portion of our audit planning effort was ensuring that the scope of our work is appropriate in addressing the identified risks of material misstatement.

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

- The financial significance of an operating unit (which will typically include multiple cons units) to bp's revenue and profit before tax, or PP&E, including consideration of the financial significance of specific account balances or transactions.
- The significance of specific risks relating to an operating unit, history of unusual or complex transactions, identification of significant audit issues or the potential for, or a history of, material misstatements.
- The effectiveness of the control environment and monitoring activities, including entity-level controls.
- The findings, observations and audit differences that we noted as a result of our 2021 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 152 reporting cons units (2021 174) which were selected based on their size or risk characteristics. There are certain cons units which 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 and Germany.

In addition, component teams performed audit procedures on specified account balances in 19 cons units (2021 32) also covering Angola, Trinidad & Tobago, Mauritania & Senegal Egypt, India, UAE and China. 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 33 cons units (2021 20).

The remaining cons units are not significant individually and include many small, low risk components and balances. On average, they each represent 0.03% of group revenue (2021 0.04%), 0.03% of property, plant and equipment (2021 0.03%) and 0.04% of profit before tax (2021 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', 'Sales and other operating revenue' and 'Profit before tax' is materially the same as in the prior year.



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 119 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).

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

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 relaxation in COVID-19 restrictions during the year, after a two year gap the senior statutory auditor and other group audit partners and staff conducted visits to meet with the component teams responsible for all of the full scope locations during the year as well as Egypt and Trinidad & Tobago. These visits included attending planning meetings, discussing the audit approach including the risk assessments and any issues arising from the component team's work, meetings with local management, and reviewing key audit working papers on higher and significant-risk areas to drive a consistent and high-quality audit. In addition, a global audit planning meeting was held in London for three days in July led by the senior statutory auditor and involving the group audit team, partners and staff from all full scope component teams, audit teams responsible for testing at key GBS locations, senior management from bp and the audit committee chair.

Following the group's decision to exit Rosneft in February 2022, Rosneft is no longer classified as a reportable segment and the investment was fully impaired. Accordingly, Rosneft was no longer a significant component in scope of the group audit and we therefore did not require reporting from Rosneft's auditor. The group audit team audited the impairment and other Rosneft related adjustments including the decision not to recognise dividends.

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.

As part of our work on other information and given the importance attached to the Underlying Replacement Cost Operating Profit metric in the annual report, we have considered the adjusting items set out on pages 353. In that context we assessed the Fair Value Accounting Effects (FVAE) adjustments, which are included within Adjusting items (as defined on page 393) which are treated as a reconciling adjustment to derive Underlying Replacement Cost Operating Profit and related underlying measures which are non-GAAP measures.

For the year ended 31 December 2022, the FVAE adjustment was a gain of \$3,501 million in arriving at underlying replacement cost profit before tax (2021 \$8,075 million gain); the cumulative unrealised gain recognised as at 31 December 2022 was \$11,436 million (2021 \$ 7,932 million). These amounts are analysed by segment on page 353; of the cumulative gain recognised, \$9,960 million (2021 \$8,149 million) relates to the gas & low carbon energy segment.

As noted on page 393, physical forward LNG contracts are not considered by bp to meet the definition of a derivative under IFRS and are therefore subject to accrual accounting meaning the fair value of forward sale and purchase contracts is not reflected in the IFRS reported results. Nevertheless, the financial contracts executed to manage price risk associated with the forward physical LNG volumes are accounted for as derivatives within the IFRS reported results, thereby creating an asymmetry.

We obtained an understanding of the amounts reported for LNG contracts within FVAE to assess consistency with the definition included within the annual report (on page 393) and with the internal policies of the group that govern the recognition and measurement of items reported within FVAE. This included understanding, and, where necessary, challenging management's application of judgement regarding the future realisation of LNG physical forward contracts.

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.

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

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.
- review of the terms of reference of the Fraud Governance Board set up by management to support the creation and delivery of the Group Fraud Risk Strategy, periodically monitor the threat outlook and review the risk appetite.
- review of the Fraud Governance Board's meeting minutes and its fraud risk assessment.
- 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.

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, United Kingdom adopted international accounting standards and IFRSs as issued by the IASB and as adopted by the EU, FRS 101, US Securities Exchange Act 1934 and relevant SEC regulations, as well as laws and regulations prevailing in each country in which we identified a full-scope component.

In addition, we considered provisions of other laws and regulations that do not have a direct effect on the financial statements but compliance with which may be fundamental to the group's ability to operate or to avoid a material penalty. These included the group's operating licences 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
- obtaining 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 150
- 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 150
- the directors' statement on fair, balanced and understandable set out on page 150
- the board's confirmation that it has carried out a robust assessment of the emerging and principal risks set out on page 69
- the section of the annual report that describes the review of effectiveness of risk management and internal control systems set out on page 149 and
- the section describing the work of the audit committee set out on pages 102-109.

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

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 2022, 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 2023 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 5 years, covering the years ending 31 December 2018 to 31 December 2022.

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
10 March 2023

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 'bp' or 'the group') as at 31 December 2022 and 2021, 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 2022, 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 group as at 31 December 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended 31 December 2022, in accordance with United Kingdom adopted international accounting standards and International Financial Reporting Standards (IFRSs) as issued by the International Accounting Standards Board (IASB) and as adopted by the European Union (EU).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), bp's internal control over financial reporting as of 31 December 2022, 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 10 March 2023 expressed an unqualified opinion on bp's internal control over financial reporting.

Basis for opinion

These financial statements are the responsibility of bp's management. Our responsibility is to express an opinion on bp'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 bp 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, 4 and 12 to the financial statements

Critical Audit Matter Description

The group balance sheet as at 31 December 2022 includes PP&E of \$106 billion, of which \$76 billion is oil and gas properties within the OP&O (\$48 billion) and G&LCE (\$28 billion) segments.

Management's oil and gas price assumptions for value-in-use impairment tests were revised in 2022 as set out in Note 1 on page 192. Brent oil price assumptions were increased in the short and medium term, reflecting management's expectation of supply constraints over the next decade due to restrictions on Russian exports, although there has been no significant change to longer term Brent oil forecasts reflecting bp's unchanged view on the longer term speed of the low carbon energy transition. Henry Hub gas price assumptions have increased until 2050, reflecting a view that US domestic gas production will need to grow, in large part to offset the loss of Russian gas exports.

Management has also revised bp's 'best estimate' discount rate assumptions for value-in-use impairment tests in 2022, as set out in Note 1 on page 192. bp's post-tax nominal weighted average cost of capital, being the starting point for setting discount rates used for impairment testing for oil and gas assets, has increased to 7%, reflecting the impact of observable increases in risk free rates on bp's weighted average cost of capital.

Given the significance of the price and discount rate assumption revisions during 2022, alongside certain CGU specific new indicators, management has tested all oil and gas CGUs for impairment and/or impairment reversal during the year. Management recorded \$2.2 billion of pre-tax oil and gas CGU impairment reversals, principally due to the oil and gas price upward revisions detailed above, and \$5.2 billion of pre-tax oil and gas CGU impairment charges due principally to increased expenditure forecasts and the increased discount rate. Further information has been provided in Note 1 on page 192 and Note 4 on page 207.

We identified three key management estimates in management's determination of the level of impairment charge and/or impairment reversal. 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, macro-economic factors and disruption in global supply due to the Russian-Ukraine war. There is a risk that management do not forecast reasonable 'best estimate' oil and gas price forecasts when assessing CGUs for impairment charge and/or impairment 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 2023 where oil and gas prices reflect near-term expected market conditions, bp'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 185, 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. Management's judgement is that the potential impact of such further emissions costs being borne by producers including bp is not expected to have a material impact on bp's oil and gas CGU carrying values as costs would effectively be borne by oil and gas end users via overall higher commodity prices. There is a risk that management's judgement is not reasonable.

Discount rates - Given the long timeframes involved, certain CGU impairment assessments are sensitive to the discount rate applied. Discount rates should reflect the return required by the market and the risks inherent in the cash flows being discounted. There is a risk that management does 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 proven and/or probable reserves estimates, that are inherently less certain than reserves; and assumptions related to these volumes can be particularly judgmental. 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 which we determined would be most at risk of material impairment charges as a result of a reasonably possible change in the oil and gas price assumptions. This population includes previously impaired assets which are also at risk of material impairment reversal resulting from potential oil and gas price assumption changes. We identified that a subset of these CGUs were also individually materially sensitive to the discount rate assumption.

We also identified CGUs which were less sensitive as they would be potentially at risk, in aggregate, to a material impairment by a reasonably possible 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 193.

Impairment charge and/or impairment 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 judgmental 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 relevant 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 charge and/or impairment 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 Conference of the Parties (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 27 in Cairo during November 2022. 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 evaluated whether they presented contradictory audit evidence.
- We challenged management's judgement, described in Note 1 on page 185, that the potential impact of further emission costs being borne by producers including bp is not expected to have a material impact on bp's oil and gas CGU carrying values. We inquired of certain third party forecasters included in our reasonable range and read 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 4, 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 bp'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 our 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 and evaluated management's disclosures in Notes 1 and 4 including in relation to the sensitivity of discount rate assumptions.

Reserves and resources estimates

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

- assessed bp's reserves and resources estimation methods and policies;
- assessed how these policies had been applied to a sample of bp's reserves and resources estimates;
- 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, capabilities 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; and

- performed a retrospective assessment to check for indications of estimation bias over time.

Other procedures

- We challenged and assessed management's CGU determinations including the evaluation of contradictory evidence.
- We assessed whether bp's impairment methodology was acceptable under IFRS and tested the integrity and mechanical accuracy of certain impairment models.
- For certain CGUs we challenged and assessed 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 production forecasts are consistent overall with bp's strategy, including the group's expectation to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 – see page 186).
- 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 23

Critical Audit Matter Description

A decommissioning provision of \$12.3 billion is recorded in the financial statements as at 31 December 2022. 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, in particular inflation and discount rate assumptions. Given management expects hydrocarbon production to be around 25% lower by 2030 relative to 2019 as stated on page 186, consistency of that expectation with the timing of decommissioning expenditure and underlying cost assumptions remains a key consideration.

Due to sustained levels of high global inflation, particularly in key geographies such as the U.S. and U.K., where a majority of bp's future decommissioning cost obligations are located, the impact of inflation on bp's decommissioning provision represents an area of particular risk. Consistent with prior years, management estimates that the average rate of forecast inflation applicable to the substantial majority of bp's decommissioning cost estimates is 1.5%, which is 0.5% lower than its estimated long term general inflation rate of 2%. As a result, the decommissioning inflation rate assumption is particularly judgmental.

The estimated undiscounted cost of its obligations and the timing of future payment are set out in Note 1 on page 199. 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.

bp increased its discount rate used in calculating its decommissioning provisions from 2.0% as at 31 December 2021 to 3.5% as at 31 December 2022. The increase was primarily driven by the increased US treasury bond rates.

Additionally, bp is 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 reversion could be elevated by the potential impact of the energy transition in particular the potential for lower oil and gas prices in the longer term which could result in financial resilience concerns for some industry participants. The risk further increased following a US legal judgement in 2020 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, 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 199 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. 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.

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.

Long term Inflation rate

- We tested the control related to the determination of the decommissioning specific inflation rate assumption.
- We tested how management derived the decommissioning specific inflation rate assumption of 1.5%, and the evidence on which it is based, by gaining an understanding of the process used by management, testing management's calculations of the assumption, and evaluating the evidence relevant to management's assumption, both supporting and contradictory.
- As the 1.5% decommissioning specific inflation rate assumption is determined by making an adjustment to management's 2.0% general long term inflation rate assumption, we evaluated, with the help of our valuation specialists, the general long term inflation rate assumption used of 2.0%, comparing it against latest external market data.
- We made inquiries with, and evaluated the competence, capabilities and objectivity, of management's decommissioning experts who derived the decommissioning specific inflation rate.
- We inspected analyst forecasts and reports in respect of the future decommissioning market and related costs for evidence of supporting and contradictory evidence, with particular focus on the future rig market.
- We particularly 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 market and related inflation assumption.
- We analysed historical trends of rig market rates against oil prices and historical inflation to challenge management's assumption that the decommissioning inflation assumption does not inflate at the same rate as general inflation.

Cost and timing estimates

- We tested the controls over the year end decommissioning cost and timing assumptions used within management's decommissioning provision estimate.
- 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 challenged whether the impact of inflation experienced in 2022 was appropriately considered and reflected where relevant within bp's cost assumptions, and also assessed the reasonableness of key cost assumptions with reference to internal and appropriate third party data.
- 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.

Discount rates

- We tested the control related to the determination of the discount rate assumption.
- With the help of our valuation specialists, we evaluated the discount rate assumption used, comparing it against latest external market data.

Reversion risk

- We obtained an understanding of bp's decommissioning reversion risk assessment process and tested relevant internal controls including those controls over the completeness and accuracy of the previously divested asset data.
- We challenged and evaluated management's key judgements related to the decommissioning reversion risk and conclusions as to 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 the 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.
- We have reviewed analysis undertaken by management, as well as third party studies, of forecast demand for refined products in regions served by bp's refineries. Furthermore, we read external profitability benchmarking which supported a conclusion that the group'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 and obtained evidence that management is developing plans for the existing refinery sites remaining in the portfolio which would be compatible with net zero emissions, for instance through the production of alternative low carbon and sustainable fuels.

We tested the decommissioning models, assessing the application of cost, timing, inflation and discount rate assumptions.

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, 20, 22, 29 and 30 to the financial statements

Critical Audit Matter Description

In the normal course of business, T&S enters into a variety of transactions for delivering value across the group's supply chain. Given the nature of these transactions, we direct significant audit effort towards challenging management's adopted accounting treatment and/or valuation estimates.

Throughout the year, we have kept our risk assessment updated by undertaking an iterative review of the underlying portfolio composition. This process facilitated a deeper understanding of the impact of commodity price volatility, demand destruction and the changing structure of the markets resulting from supply dislocations due to the Russian-Ukraine war 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 refer to the following factors to identify a SCT:

- two or more counterparties with non-standard contractual terms
- reference multiple commodity-based transactions 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, including in particular the classification of liabilities as finance debt.

Valuation of commodity derivatives:

Commodity markets remained volatile during the year on the back of continuing demand uncertainty as a result of the global energy transition, macro-economic factors and disruptions in global supply due to the Russian-Ukraine war. In response to the volatility observed, we focused our audit efforts on the valuation of all commodity derivatives and designed procedures specifically to 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 2022, bp's total derivative financial assets and liabilities measured at fair value were \$24.4 billion and \$26.2 billion, of which level 3 derivative financial assets were \$8.8 billion and level 3 derivative financial liabilities were \$7.0 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 offtake arrangements and/or significant contractual commitments.
- Selected a sample of existing working capital arrangements and financing structures to assess whether associated trading activity was in compliance with pre-determined 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 2022, we have refreshed our assessment in 2022 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 derivatives:

In response to the continuing high 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 derivatives at 30 June and of distinct samples of both Level 2 and Level 3 derivatives at 30 September and 31 December. In addition, we 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 our valuation specialists to challenge models, develop fair value estimates and evaluate 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, investments in joint ventures and refinery PP&E as a consequence, inter alia, of climate change and the energy transition – Notes 1, 4, 15 and 16

Critical Audit Matter Description

Intangible Assets

The recoverability of certain of the group's \$4.2 billion total exploration and appraisal (E&A) assets capitalised as at 31 December 2022 are potentially exposed to climate change and the global energy transition risk factors (see Note 15). This is because a greater number of E&A projects may not proceed as a consequence of the energy transition leading to lower forecast future oil and gas prices and bp's intention to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 – see page 186). 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 and continues to require significant management judgement.

PP&E and Investment in joint ventures

The carrying value of bp'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. Management identified impairment indicators in respect of certain refineries during the year. As a result, impairment tests were performed to assess the recoverability of the refineries' carrying values. As disclosed in Note 4 to the accounts on page 208, management has recorded an impairment charge of \$1,366 million in respect of the Gelsenkirchen refinery in Germany, driven by changes in economic assumptions.

bp's intention to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 - see page 186) and the group's wider strategy includes potentially disposing of certain higher emissions intensity upstream oil assets and others. As a consequence, for certain assets and investments 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 \$2.9 billion of pre-tax impairment charges in 2022 for such potential disposals as described in Note 4. There is a 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 carrying value of the group's investments in low carbon energy assets may no longer be recoverable due to an increase in the low carbon energy discount rate, project development costs increasing as a result of higher inflation and the impact that the increased activity within the sector, as a result of the energy transition, has had on the demand for low carbon energy supply chain goods and services.

How the Critical Audit Matter Was Addressed in the Audit

We utilised 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.

Intangible Assets

In respect of the recoverability of E&A assets capitalised as at 31 December 2022:

- We obtained an understanding of the group's E&A write-off and impairment assessment processes and tested relevant internal controls, which specifically consider 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 judgements with 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, reading meeting minutes and reviewing licence documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms.
- We 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 and bp's intention to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 - see page 186).

PP&E and Investment in joint ventures

We have considered the impact of potential changes in supply and demand on the group's refining portfolio and reviewed internal and external market studies of future supply and demand. In relation to the Gelsenkirchen refinery impairment test, we assessed the valuation methodology, tested the integrity and mechanical accuracy of the impairment model and assessed the appropriateness of key assumptions and inputs, notably forecast refining margins and energy input costs, challenging and evaluating management's assumptions by reference to third party data where available. 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 test and related inputs.

We challenged management's analysis, that identified the specific assets that are likely to be disposed of by bp 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, carefully considered bp's strategic intent in this context and challenged management's assessment of the recoverable amounts for material transactions. We also tested related relevant controls which covered both the recoverable amounts determined and the likelihood of transaction completion.

In respect of the impairment tests performed on certain low carbon energy investments, we tested the result by:

- Testing the relevant controls over low carbon energy impairment tests including controls over key assumptions and the discount rate
- Assessing the low carbon energy discount rate with input from our valuation specialists
- Challenging and evaluating the key assumptions within the impairment tests, which included capital and operating cost assumptions, forecast yield and power price assumptions, debt and interest assumptions, and the applicability of the Inflation Reduction Act legislation on investment credit assumptions and
- Testing the mechanical accuracy of the impairment models.

/s/ Deloitte LLP

London
United Kingdom
10 March 2023

We have served as the bp'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 its subsidiaries (the 'group') as of 31 December 2022, 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 group maintained, in all material respects, effective internal control over financial reporting as of 31 December 2022, 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 2022, of the group and our report dated 10 March 2023 expressed an unqualified opinion on those financial statements.

As described in Management's report on internal control over financial reporting, management excluded from its assessment the internal control over financial reporting at 'Archaea Energy' and 'EDF Energy Services', which were acquired on 28 December 2022 and 30 November 2022 respectively. Archaea Energy's financial statements constitute 5.6% and 2.1% of net and total assets, respectively, Nil % of 'Sales and other operating revenues', and 2.2% of 'profit (loss) for the year' of the consolidated financial statement amounts as of and for the year ended 31 December 2022. EDF Energy Services financial statements constitute 0.7% and 1.0% of net and total assets, respectively, Nil % of 'Sales and other operating revenues', and 1.3% of 'profit (loss) for the year' of the consolidated financial statement amounts as of and for the year ended 31 December 2022. Accordingly, our audit did not include the internal control over financial reporting at Archaea Energy and EDF Energy Services.

Basis for opinion

The group'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 group'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 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 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
10 March 2023

- 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	2022	2021	2020
Sales and other operating revenues	6	241,392	157,739	105,944
Earnings from joint ventures – after interest and tax	16	1,128	543	(302)
Earnings from associates – after interest and tax	17	1,402	3,456	(101)
Interest and other income	7	1,103	581	663
Gains on sale of businesses and fixed assets	4	3,866	1,876	2,874
Total revenues and other income		248,891	164,195	109,078
Purchases	19	141,043	92,923	57,682
Production and manufacturing expenses		28,610	25,843	22,494
Production and similar taxes	5	2,325	1,308	695
Depreciation, depletion and amortization	5	14,318	14,805	14,889
Net impairment and losses on sale of businesses and fixed assets	4	30,522	(1,121)	14,381
Exploration expense	8	585	424	10,280
Distribution and administration expenses		13,449	11,931	10,397
Profit (loss) before interest and taxation		18,039	18,082	(21,740)
Finance costs	7	2,703	2,857	3,115
Net finance (income) expense relating to pensions and other post-retirement benefits	24	(69)	(2)	33
Profit (loss) before taxation		15,405	15,227	(24,888)
Taxation	9	16,762	6,740	(4,159)
Profit (loss) for the year		(1,357)	8,487	(20,729)
Attributable to				
bp shareholders		(2,487)	7,565	(20,305)
Non-controlling interests		1,130	922	(424)
		(1,357)	8,487	(20,729)
Earnings per share				
Profit (loss) for the year attributable to bp shareholders				
Per ordinary share (cents)				
Basic	11	(13.10)	37.57	(100.42)
Diluted	11	(13.10)	37.33	(100.42)
Per ADS (dollars)				
Basic	11	(0.79)	2.25	(6.03)
Diluted	11	(0.79)	2.24	(6.03)

Group statement of comprehensive income^a

For the year ended 31 December		\$ million		
	Note	2022	2021	2020
Profit (loss) for the year		(1,357)	8,487	(20,729)
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		(3,786)	(921)	(1,843)
Exchange (gains) losses on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		10,759	36	(353)
Cash flow hedges marked to market	30	(825)	(430)	78
Cash flow hedges reclassified to the income statement	30	1,502	255	(37)
Costs of hedging marked to market	30	61	(105)	42
Costs of hedging reclassified to the income statement	30	25	21	22
Share of items relating to equity-accounted entities, net of tax	16, 17	402	44	312
Income tax relating to items that may be reclassified	9	(334)	65	66
		7,804	(1,035)	(1,713)
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	24	340	4,416	170
Cash flow hedges that will subsequently be transferred to the balance sheet	30	(4)	1	7
Income tax relating to items that will not be reclassified	9	68	(1,317)	(105)
		404	3,100	72
Other comprehensive income		8,208	2,065	(1,641)
Total comprehensive income		6,851	10,552	(22,370)
Attributable to				
bp shareholders		5,782	9,654	(21,983)
Non-controlling interests		1,069	898	(387)
		6,851	10,552	(22,370)

^a See Note 32 for further information.

Group statement of changes in equity^a

	\$ million								
	Share capital and capital reserves	Treasury shares	Foreign currency translation reserve	Fair value reserves	Profit and loss account	bp shareholders' equity	Hybrid bonds	Other interest	Total equity
At 1 January 2022	46,871	(12,624)	(9,572)	(1,027)	51,815	75,463	13,041	1,935	90,439
Profit for the year	—	—	—	—	(2,487)	(2,487)	519	611	(1,357)
Other comprehensive income	—	—	6,914	770	585	8,269	—	(61)	8,208
Total comprehensive income	—	—	6,914	770	(1,902)	5,782	519	550	6,851
Dividends ^b	—	—	—	—	(4,365)	(4,365)	—	(294)	(4,659)
Cash flow hedges transferred to the balance sheet, net of tax	—	—	—	1	—	1	—	—	1
Issue of ordinary share capital	820	—	—	—	—	820	—	—	820
Repurchase of ordinary share capital	—	—	—	—	(10,493)	(10,493)	—	—	(10,493)
Share-based payments, net of tax	182	471	—	—	194	847	—	—	847
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—	—	—	—	—
Issue of perpetual hybrid bonds	—	—	—	—	(4)	(4)	374	—	370
Payments on perpetual hybrid bonds	—	—	15	—	—	15	(544)	—	(529)
Tax on issue of perpetual hybrid bonds	—	—	—	—	—	—	—	—	—
Transactions involving non-controlling interests, net of tax	—	—	—	—	(513)	(513)	—	(144)	(657)
At 31 December 2022	47,873	(12,153)	(2,643)	(256)	34,732	67,553	13,390	2,047	82,990
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	—	—	—	—	(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	—	—	—	—	(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

^a See Note 31 for further information.

^b See Note 10 for further information.

Group balance sheet

At 31 December			\$ million
	Note	2022	2021
Non-current assets			
Property, plant and equipment	12	106,044	112,902
Goodwill	14	11,960	12,373
Intangible assets	15	10,200	6,451
Investments in joint ventures	16	12,400	9,982
Investments in associates ^a	17	8,201	21,001
Other investments	18	2,670	2,544
Fixed assets		151,475	165,253
Loans		1,271	922
Trade and other receivables	20	1,092	2,693
Derivative financial instruments	30	12,841	7,006
Prepayments		576	479
Deferred tax assets	9	3,908	6,410
Defined benefit pension plan surpluses	24	9,269	11,919
		180,432	194,682
Current assets			
Loans		315	355
Inventories	19	28,081	23,711
Trade and other receivables	20	34,010	27,139
Derivative financial instruments	30	11,554	5,744
Prepayments		2,092	2,486
Current tax receivable		621	542
Other investments	18	578	280
Cash and cash equivalents	25	29,195	30,681
		106,446	90,938
Assets classified as held for sale	2	1,242	1,652
		107,688	92,590
Total assets		288,120	287,272
Current liabilities			
Trade and other payables	22	63,984	52,611
Derivative financial instruments	30	12,618	7,565
Accruals		6,398	5,638
Lease liabilities	28	2,102	1,747
Finance debt	26	3,198	5,557
Current tax payable		4,065	1,554
Provisions	23	6,332	5,256
		98,697	79,928
Liabilities directly associated with assets classified as held for sale	2	321	359
		99,018	80,287
Non-current liabilities			
Other payables	22	10,387	10,567
Derivative financial instruments	30	13,537	6,356
Accruals		1,233	968
Lease liabilities	28	6,447	6,864
Finance debt	26	43,746	55,619
Deferred tax liabilities	9	10,526	8,780
Provisions	23	14,992	19,572
Defined benefit pension plan and other post-retirement benefit plan deficits	24	5,244	7,820
		106,112	116,546
Total liabilities		205,130	196,833
Net assets		82,990	90,439
Equity			
bp shareholders' equity	32	67,553	75,463
Non-controlling interests	32	15,437	14,976
Total equity	32	82,990	90,439

^a See Note 1 - Significant judgements and estimate: investment in Rosneft for further information.

Helge Lund Chair

Bernard Looney Chief executive officer

10 March 2023

Group cash flow statement

For the year ended 31 December		\$ million		
	Note	2022	2021	2020
Operating activities				
Profit (loss) before taxation		15,405	15,227	(24,888)
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	8	385	167	9,920
Depreciation, depletion and amortization	5	14,318	14,805	14,889
Impairment and (gain) loss on sale of businesses and fixed assets	4	26,656	(2,997)	11,507
Earnings from joint ventures and associates		(2,530)	(3,999)	403
Dividends received from joint ventures and associates		1,700	1,842	1,442
Interest receivable		(444)	(235)	(258)
Interest received		414	320	74
Finance costs	7	2,703	2,857	3,115
Interest paid		(2,208)	(2,474)	(2,728)
Net finance expense relating to pensions and other post-retirement benefits	24	(69)	(2)	33
Share-based payments		795	627	723
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	24	(257)	(655)	(282)
Net charge for provisions, less payments		440	2,934	735
(Increase) decrease in inventories		(5,492)	(7,458)	3,963
(Increase) decrease in other current and non-current assets		(18,584)	(13,263)	4,230
Increase (decrease) in other current and non-current liabilities		17,806	20,095	(8,278)
Income taxes paid		(10,106)	(4,179)	(2,438)
Net cash provided by operating activities		40,932	23,612	12,162
Investing activities				
Expenditure on property, plant and equipment, intangible and other assets		(12,069)	(10,887)	(12,306)
Acquisitions, net of cash acquired	3	(3,530)	(186)	(44)
Investment in joint ventures		(600)	(1,440)	(567)
Investment in associates		(131)	(335)	(1,138)
Total cash capital expenditure		(16,330)	(12,848)	(14,055)
Proceeds from disposals of fixed assets	4	709	1,145	491
Proceeds from disposals of businesses, net of cash disposed	4	1,841	5,812	4,989
Proceeds from loan repayments		67	197	717
Net cash used in investing activities		(13,713)	(5,694)	(7,858)
Financing activities				
Repurchase of shares		(9,996)	(3,151)	(776)
Lease liability payments		(1,961)	(2,082)	(2,442)
Proceeds from long-term financing		2,013	6,987	14,736
Repayments of long-term financing		(11,697)	(16,804)	(12,179)
Net increase (decrease) in short-term debt		(1,392)	1,077	(1,234)
Issue of perpetual hybrid bonds		370	924	11,861
Payments relating to perpetual hybrid bonds		(708)	(538)	(89)
Payments relating to transactions involving non-controlling interests (other)		(9)	(560)	(8)
Receipts relating to transactions involving non-controlling interests (other)		11	683	665
Dividends paid				
bp shareholders	10	(4,358)	(4,304)	(6,340)
Non-controlling interests		(294)	(311)	(238)
Net cash provided by (used in) financing activities		(28,021)	(18,079)	3,956
Currency translation differences relating to cash and cash equivalents		(684)	(269)	379
Increase (decrease) in cash and cash equivalents		(1,486)	(430)	8,639
Cash and cash equivalents at beginning of year		30,681	31,111	22,472
Cash and cash equivalents at end of year		29,195	30,681	31,111

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 2022 were approved and signed by the chief executive officer and chairman on 10 March 2023 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 United Kingdom adopted international accounting standards and International Financial Reporting Standards (IFRSs) as issued by the International Accounting Standards Board (IASB) and as adopted by the European Union (EU) and in accordance with the provisions of the UK Companies Act 2006 as applicable to companies reporting under international accounting standards. 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 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 2022. 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; the formation of Azule Energy, 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; pensions and other post-retirement benefits; and taxation. Judgements and estimates, not all of which are significant, made in assessing the impact of the current economic and geopolitical environment, 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 28) 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 and gas price assumptions for value-in-use impairment testing are aligned with those investment appraisal assumptions, except for 2023 oil and gas prices which reflect near-term market conditions. The assumptions for future carbon emissions costs in value-in-use impairment testing differ from the investment appraisal assumptions and are 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 and natural gas price assumptions for value-in-use impairment testing were revised during 2022. Prices are disclosed in real 2021 terms. The Brent oil assumption from 2024 up to 2030 was increased to \$70 per barrel to reflect near-term supply constraints before steadily declining to \$45 per barrel by 2050 continuing to reflect the assumption that as the energy system decarbonizes, falling oil demand will cause oil prices to decline. The price assumptions for Henry Hub gas up to 2035 and up to 2050 were increased to \$4.00 per mmBtu and \$3.50 per mmBtu respectively, reflecting increased demand for US gas production to offset reduced Russian gas flows. 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 is 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 impacted 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

Where we consider that the outcome of a value-in-use impairment test could be significantly affected by a carbon price in place in any jurisdiction, this is incorporated into the value-in-use impairment testing cash flows. The most significant instances where a carbon price has been incorporated in this way are for the UK North Sea and Gelsenkirchen refinery, where assumptions of approximately £100/tCO₂e and an average of approximately €70/tCO₂e were applied in the 2022 value-in-use impairment tests respectively.

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 sees the expected reduction in upstream hydrocarbon production by around 25% by 2030 from its 2019 baseline (see page 11) being achieved through future active management, including divestments, and high-grading of the portfolio. Changes in upstream production since 2019 will be included in the best estimate to the extent the divestments have been announced or completed however, as the specific future changes to the remainder of the portfolio are not yet known, the current best estimate used for accounting purposes does not include the full extent of the expected upstream production reduction. See significant judgements and estimates: recoverability of asset carrying values and Note 14 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 4 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 the group's exploration and appraisal intangible assets were written off in 2020 and the recoverability of the remaining intangibles was considered during 2022. 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 8 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, a 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. The significant majority of refining assets, recognized on the group's balance sheet at 31 December 2022 that are subject to depreciation, will be depreciated within the next 12 years; demand for refined products is expected to remain sufficient to support the remaining useful lives 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 as well as renewal and/or replacement of aged assets 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 25% by 2030 from its 2019 baseline (see page 11) is expected to be achieved through future active management, including divestments, 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 a reasonably possible change of two years in the expected timing of all 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. Decommissioning provisions relating to refineries at 31 December 2022 are not material. See significant judgements and estimates: provisions for further information.

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

Judgements and estimates made in assessing the impact of the geopolitical and 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 current geopolitical and economic environment.

Oil and gas price assumptions

The near-term oil and gas price assumptions applied in value-in-use impairment testing have been increased to reflect current supply constraints and increased demand for gas to replace Russian supply. See significant judgements and estimates: recoverability of asset carrying values 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 increased twice during the year to reflect rising US Treasury yields. The principal impact of these rate increases was a \$3.2 billion decrease in the decommissioning provision with an associated decrease in the carrying amount of property, plant and equipment of \$2.5 billion and a pre-tax credit to the income statement of \$0.7 billion. Impairment discount rates were also increased from those reported in 2021. 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 2022 impacted the assumptions used for determining the fair value of plan assets and the present value of defined benefit obligations in the group's defined benefit pension plans. See significant estimate: pensions and other post-retirement benefits and Note 24 for further information.

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.

For joint arrangements in a separate entity, judgement may be required as to whether the arrangement should be classified as a joint venture or if the legal form, contractual arrangements or other facts and circumstances indicate that the group has rights to the assets and obligations for the liabilities of the arrangement, rather than rights to the net assets, and therefore should be classified as a joint operation. No such judgement made by the group is considered significant.

Interests in associates

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

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

Significant judgement: investment in 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 judgement that the group continues to have significant influence over Aker BP, a Norwegian oil and gas company, following completion of Aker BP's acquisition of Lundin Energy's oil and gas business, is significant.

As a consequence of this judgement, bp uses the equity method of accounting for its investment and bp's share of Aker BP's oil and natural gas reserves is included in the group's estimated net proved reserves of equity-accounted entities. If significant influence was not present, the investment would be accounted for as an investment in an equity instrument measured at fair value as described under 'Financial assets' below and no share of Aker BP's oil and natural gas reserves would be reported.

Significant influence is defined in IFRS as the power to participate in the financial and operating policy decisions of the investee but is not control or joint control of those decisions. 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.

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's oil and gas business on 30 June 2022, bp's interest was 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 owned 15.9% of the voting shares at 31 December 2022.

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. 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 retained significant influence, as defined by IFRS, over Aker BP following the acquisition of Lundin Energy's oil and gas business and continues to have significant influence at 31 December 2022.

Significant judgements and estimate: investment in Rosneft

On 27 February 2022, bp announced it will exit its shareholding in Rosneft and bp's two nominated Rosneft directors both stepped down from Rosneft's board. As a result, the significant judgement on significant influence over Rosneft was reassessed and a new significant estimate was identified for the fair value of bp's equity investment in Rosneft. From that date, bp accounts for its interest in Rosneft as a financial asset measured at fair value within 'Other investments'. Russia has implemented a number of counter-sanctions including restrictions on the divestment of Russian assets by foreign investors. Further, bp is not able to sell its Rosneft shares on the Moscow Stock Exchange and is unable to ascribe probabilities to possible outcomes of any exit process. As a result, it is considered that any measure of fair value, other than \$nil, would be subject to such high measurement uncertainty that no estimate would provide useful information even if it were accompanied by a description of the estimate made in producing it and an explanation of the uncertainties that affect the estimate. Accordingly, it is not currently possible to estimate any carrying value other than \$nil when determining the measurement of the interest in Rosneft as at 31 December 2022. Events or outcomes within the next financial year, that are different to those outlined above, could materially change the fair value of the investment.

During 2022, Rosneft has held shareholder meetings to approve resolutions to pay dividends. bp did not participate in those meetings. In line with the resolutions, bp would be entitled to dividend income. Russia has imposed restrictions on the payments of dividends to certain foreign shareholders, including those based in the UK, requiring such dividends to be paid in roubles into restricted bank accounts and a requirement for approval of the Russian government for transfers from any such bank accounts out of Russia. Given the restrictions applicable to such accounts, management has made the significant judgement that the criteria for recognizing any dividend income from Rosneft for the year to 31 December 2022 have not been met.

Since the first quarter 2022, bp has also determined that its other businesses with Rosneft within Russia, which are included in the oil production & operations segment also have a fair value of \$nil and are subject to similar sanctions and restrictions with respect to the receipt of dividends as described above. Management considers that the criteria for recognizing dividend income from other businesses with Rosneft within Russia that declared a dividend during 2022 have not been met.

The total pre-tax charge during the year-ended 31 December 2022 relating to bp's investment in Rosneft and other businesses with Rosneft in Russia is \$25,520 million.

Significant judgement: formation of Azule Energy

On 1 August 2022, Azule Energy, an independent incorporated 50:50 joint venture, between bp and Eni, was formed through the combination of the two companies' Angolan businesses. As part of the consideration for contributing its assets, bp received 500,000 shares in Azule Energy. The group determined that the fair value of these shares at the date of the transaction was \$6.9 billion and the transaction resulted in a gain on disposal of \$3.9 billion, of which 50% has been deferred against the investment on the balance sheet and will be amortised over time, consistent with bp's accounting policy for unrealized gains on transactions between the group and equity-accounted entities. The fair value was determined using a discounted cash flow analysis with judgments over the assumptions including capital expenditure, costs, production and commodity price forecasts, and a post-tax discount rate that would be applied by a market participant.

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 typically 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. This includes unrealized gains arising on contribution of a business on formation of an equity-accounted entity.

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

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. bp changed its segmental reporting during 2022, see 'Changes in segmentation' below.

For further information see Note 5.

Foreign currency translation

In individual subsidiaries, joint ventures and associates, transactions in foreign currencies are initially recorded in the functional currency of those entities at the spot exchange rate on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the spot exchange rate on the balance sheet date. Any resulting exchange differences are included in the income statement, unless hedge accounting is applied. Non-monetary 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, biogas rights agreements, digital assets, 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. The expected useful life of biogas rights agreements is the shorter of the duration of the legal agreement and economic useful life and can be up to 50 years. Digital asset 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.

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

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.

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 8.

Property, plant and equipment

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

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

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 12 and Note 5 respectively.

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

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

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

The estimation of oil and natural gas reserves and bp's process to manage reserves bookings is described in Supplementary information on oil and natural gas on page 263, which is unaudited. Details on bp's proved reserves and production compliance and governance processes are provided on page 361. The 2022 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 263.

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

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

Impairment of property, plant and equipment, intangible assets, goodwill, and equity-accounted entities

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 inflows that are largely independent of the cash inflows 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, power generation, 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, power 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. Fair value may be determined by reference to agreed or expected sales proceeds, recent market transactions for similar assets or using discounted cash flow analyses. 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 or CGU's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset or CGU 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 or CGU 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 or CGU'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.

The group assesses investments in equity-accounted entities for impairment whenever there is objective evidence that the investment is impaired, after recognizing its share of any losses of the equity-accounted entity itself. 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.

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

Significant judgements and estimates: recoverability of asset carrying values

Determination as to whether, and by how much, an asset, CGU, or group of CGUs containing goodwill is impaired involves management estimates on highly uncertain matters such as the effects of inflation and deflation on operating expenses, discount rates, capital expenditure, 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, power and refined products. Judgement is required when determining the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment testing purposes. For example, individual oil and gas properties may form separate CGUs whilst certain oil and gas properties with shared infrastructure may be grouped together to form a single CGU. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing. See Note 14 for details on how these groupings have been determined in relation to the impairment testing of goodwill.

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

Details of impairment charges and reversals recognized in the income statement are provided in Note 4 and details on the carrying amounts of assets are shown in Note 12, Note 14 and Note 15.

The estimates for assumptions made in impairment tests in 2022 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.

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 2022, the post-tax discount rate was 7% (2021 6%) other than for low carbon energy assets. Where the CGU is located in a country that was judged to be higher risk an additional premium of 1% to 2% was reflected in the post-tax discount rate (2021 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, other than for low carbon energy assets, typically ranged from 7% to 18% (2021 7% to 15%) depending on the risk premium and applicable tax rate in the geographic location of the CGU. For low carbon energy assets where the risk profile of expected cash flows supports a lower rate, the post-tax discount rate for fair value less costs of disposal impairment tests was 6%.

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, 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 2022, the group identified oil and gas properties in these segments with carrying amounts totalling \$11,652 million (2021 \$26,341 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 185. 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 (in real 2021 terms) for Brent oil from 2024 up to 2030 was increased to \$70 per barrel to reflect near term supply constraints before steadily declining to \$45 per barrel by 2050 continuing to reflect the assumption that as the energy system decarbonises, falling oil demand will cause oil prices to decline. The price assumptions for Henry Hub gas up to 2035 and up to 2050 were increased to \$4.00 per mmBtu and \$3.50 per mmBtu respectively to reflect the increased demand for US gas production to offset reduced Russian gas flows. These price assumptions are derived from the central case investment appraisal assumptions, adjusted where applicable to reflect short-term market conditions (see page 28). A summary of the group's revised price assumptions for Brent oil and Henry Hub gas, applied in 2022 and 2021, in real 2021 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% (2021 2%) is applied to determine the price assumptions in nominal terms.

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 recoverability of deferred tax assets is also affected by the group's oil and natural gas price assumptions as these could impact the estimate of future taxable profits. See Note 9 for further information.

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

2022 price assumptions	2023	2025	2030	2040	2050
Brent oil (\$/bbl)	77	70	70	58	45
Henry Hub gas (\$/mmBtu)	4.00	4.00	4.00	3.50	3.50
2021 price assumptions	2022	2025	2030	2040	2050
Brent oil (\$/bbl)	71	61	61	56	46
Henry Hub gas (\$/mmBtu)	4.08	3.06	3.06	3.06	2.80

Global oil production increased by 4.9% in 2022. Despite western sanctions on Russian oil exports, Russian export volumes remain at 97% of pre-invasion levels, as oil shipments to the EU and OECD Asian countries are redirected to China, India, and Türkiye. Global oil demand continued its post-COVID-19 recovery, increasing by 2.3% in 2022. Europe's energy crisis, a strong US dollar, and persistent COVID-19 lockdowns in China all contributed to slower energy demand growth and weaker oil demand growth. Brent increased by \$30 per barrel in 2022 as a result of the rebound in oil demand and the oil risk premium associated with the Russia-Ukraine war. bp's long-term assumption for oil prices is lower than the 2022 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 increased around two-thirds to \$6.4 per mmBtu in 2022. The higher prices reflect much tighter demand supply balance for most of 2022. Through April, lower production particularly in Appalachia, depleted gas stocks to 90% of the five-year average, increasing prices. Thereafter, while production recovered, a record warm summer and lower coal stocks at power plants increased the call on gas fired generation, keeping demand strong and preventing gas stocks from rebuilding. This, was despite an outage at the Freeport LNG terminal since June reducing the demand for LNG exports. Further, industrial demand was further boosted by geopolitical disruptions that increased global product prices, favouring US firms due to relatively lower feedstock costs. Prices only moderated in the fourth quarter when growth in production and moderate weather allowed gas inventories to be replenished. The level of US gas prices in 2022 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 changes in net revenue cash flows in value-in-use impairment testing under the following sensitivity analyses: an increase in net revenues of 10% in all years up to 2030, 25% in all subsequent years to 2040 and 40% in all remaining years to 2050; and a decrease in net revenues of 25% in all years up to 2030, 50% in all subsequent years to 2040 and 60% in all remaining years to 2050.

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 \$15-16 billion, which is approximately 14-15% of the net book value of property, plant and equipment as at 31 December 2022. If this net revenue reduction was due to reductions in prices in isolation, it reflects an indicative decrease in the carrying amount of using price assumptions for Brent oil trending broadly towards the bottom of the range of prices associated with 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. This 'family' of scenarios is also used in bp's TCFD scenario analysis (see page 50).

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 \$1-2 billion, which is approximately 1-2% of the net book value of property, plant and equipment as at 31 December 2022. 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 2022. If this net revenue increase was due to increases in prices in isolation, it reflects an indicative increase in the carrying amount of using price assumptions for Brent oil trending broadly towards the top end until 2040, and then towards the mean average at 2050, of the range of prices associated with the WBCSD 'family' of scenarios considered to be consistent with limiting global average temperature to 1.5°C above pre-industrial levels. This 'family' of scenarios is also used in bp's TCFD scenario analysis.

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

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 the group's 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 2022 would have been approximately \$0.5 billion lower. If the discount rate was one percentage point lower, the net impairment reversal recognized would have been approximately \$0.5 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 \$12.0 billion on its balance sheet (2021 \$12.4 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. Of this, \$7.2 billion relates to goodwill in the oil production & operations and gas & low carbon energy segments (2021 \$7.6 billion), 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 14.

Inventories

Inventories, other than inventories held for short-term trading purposes, are stated at the lower of cost and net realizable value. Cost is typically 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. For the majority of the leases in the group, there is not sufficient information available to readily determine the rate implicit in the lease, and therefore the 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.

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

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 agreement. 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 income is recognized using the effective interest method. This category of financial assets includes trade and other receivables.

Financial assets measured at fair value through other comprehensive income

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

Financial assets measured at fair value through profit or loss

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

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 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 directly attributable issue costs.

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

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. At 31 December 2022, trade payables subject to these arrangements and this significant judgement included \$9.5 billion (2021 \$9.2 billion) payable to the providers of the letters of credit. See Note 29 - Liquidity risk for further information.

Financial guarantees

The group issues financial guarantee contracts to make specified payments to reimburse holders for losses incurred if 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 contractual cash flows 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.

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

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.

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.

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 are accounted for on an accruals basis, rather than as a derivative. Under IFRS, bp fair values the derivative financial instruments used to risk-manage the LNG contracts themselves, resulting in a measurement mismatch.

For more information, including the carrying amounts of level 3 derivatives, see Note 30.

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 3.5% (2021 2.0%).

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

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.

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

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 a 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 majority of these provisions are typically settled within 12 months of the balance sheet date however certain schemes may have longer compliance periods. 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.

Restructuring provisions

Restructuring provisions are recognized 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.

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

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, where still recognized, 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. This typically requires assessment of the local legal requirements and the financial standing of the owner. If the standing deteriorates significantly, for example, bankruptcy of the owner, a provision may be required. The group has assessed that \$0.8 billion of decommissioning provisions should be recognized as at 31 December 2022 (2021 \$0.5 billion) for assets previously sold to third parties where the sale transferred the decommissioning obligation to the new owner. See Note 33 for further information.

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 33 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 2022 was 3.5% (2021 2.0%), which was based on long-dated US government bonds. The weighted average period over which decommissioning and environmental costs are generally expected to be incurred is estimated to be approximately 17 years (2021 17 years) and 6 years (2021 6 years) respectively. Costs at future prices are typically determined by applying an inflation rate of 1.5% (2021 1.5%) to decommissioning costs and 2% (2021 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 \$5.6 billion (2021 \$5.3 billion) within the next 10 years, \$5.3 billion (2021 \$6.9 billion) in 10 to 20 years and the remainder of approximately \$6.0 billion (2021 \$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 1.0 percentage point increase in the nominal discount rate applied could decrease the group's provision balances by approximately \$1.8 billion (2021 \$2.6 billion). The pre-tax impact on the group income statement would be a credit of approximately \$0.5 billion (2021 \$0.7 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 \$0.5 billion (2021 \$0.2 billion). Management currently does not consider a change of greater than two years to be reasonably possible in the next financial year and therefore the timing of upstream decommissioning expenditure is not a key source of estimation uncertainty.

If all expected future decommissioning expenditures were 10% higher, then these decommissioning provisions would increase by approximately \$1.2 billion (2021 \$1.6 billion) and a pre-tax charge of approximately \$0.3 billion (2021 \$0.4 billion) would be recognized. A one percentage point increase in the inflation rate applied to upstream decommissioning costs to determine the nominal cash flows could increase the decommissioning provision by approximately \$2.0 billion (2021 \$2.9 billion) with a pre-tax charge of approximately \$0.5 billion (2021 \$0.7 billion).

As described in Note 33, the group is subject to claims and actions for which no provisions have been recognized. The facts and circumstances relating to particular cases are evaluated regularly in determining whether a provision relating to a specific litigation should be recognized or revised. Accordingly, significant management judgement relating to provisions and contingent liabilities is required, since the outcome of litigation is difficult to predict.

Employee benefits

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

Share-based payments

Equity-settled transactions

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

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

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 24.

Income taxes

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

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

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

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

- Where the deferred tax liability arises on the initial recognition of goodwill.
- Where the deferred tax liability arises on the initial recognition of an asset or liability in a transaction that is not a business combination, 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.

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

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.

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.

Significant judgement and estimate: taxation

The value of deferred tax assets and liabilities is an area involving inherent uncertainty and estimation and balances are therefore subject to risk of material change as a result of underlying assumptions and judgements used, in particular the forecast of future profitability used to determine the recoverability of deferred tax, for example future oil and gas prices, see 'Significant judgement and estimates - Recoverability of asset carrying values'. It is impracticable to disclose the extent of the possible effects of profitability assumptions on the group's deferred tax assets. It is reasonably possible that to the extent that actual outcomes differ from management's estimates, material income tax charges or credits, and material changes in current and deferred tax assets or liabilities, may arise within the next financial year and in future periods.

Judgement is required when determining whether a particular tax is an income tax or another type of tax (for example, a production tax). The attributes of the tax, including whether it is calculated on profits or another measure such as production or revenues, the extent of deductibility of costs and the interaction with existing income taxes, are considered in determining the classification of the 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.

This judgement is considered significant only in relation to the group's taxes payable under the fiscal terms of bp's onshore concession in Abu Dhabi. These are principally reported as income taxes rather than as production taxes.

For more information see Note 9 and Note 33.

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.

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

Own equity instruments – treasury shares

The group's holdings in its own equity instruments are shown as deductions from shareholders' equity. 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.

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

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

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 been endorsed by the UK and the EU. The new standard is not expected to have a material effect on bp's net assets as at 1 January 2023 or 1 January 2022.

Other changes to significant accounting policies

Change in segmentation

As a result of bp's decision to exit its shareholding in Rosneft on 27 February 2022, the group has ceased to report Rosneft as a separate segment in its financial reporting for 2022. Rosneft results up to 27 February 2022 are included within other businesses & corporate (OB&C), and 2021 and 2020 comparatives have been restated to include the Rosneft segment as per the table below:

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

	2021			2020		
	OB&C (as previously reported)	Rosneft (as previously reported)	OB&C restated	OB&C (as previously reported)	Rosneft (as previously reported)	OB&C restated
Profit (loss) before interest and tax	(2,777)	2,688	(89)	(579)	(238)	(817)
Inventory holding (gains) losses*	—	(259)	(259)	—	89	89
RC profit (loss) before interest and tax	(2,777)	2,429	(348)	(579)	(149)	(728)
Net (favourable) adverse impact of adjusting items	1,394	291	1,685	(303)	205	(98)
Underlying RC profit (loss) before interest and tax	(1,383)	2,720	1,337	(882)	56	(826)
Taxation on an underlying RC basis	294	(269)	25	37	(3)	34
Underlying RC profit (loss) before interest	(1,089)	2,451	1,362	(845)	53	(792)

\$ million

2. Non-current assets held for sale

The carrying amount of assets classified as held for sale at 31 December 2022 is \$1,242 million (2021 \$1,652 million), with associated liabilities of \$321 million (2021 \$359 million).

gas & low carbon energy

On 7 September 2022, bp announced that it had agreed to sell its upstream business in Algeria to Eni. The sale completed on 28 February 2023. Assets of \$511 million and associated liabilities of \$48 million were classified as held for sale in the group balance sheet at 31 December 2022.

customers & products

On 8 August 2022, bp announced an agreement to sell its 50% interest in the bp-Husky Toledo refinery in Ohio US, to Cenovus Energy, its partner in the facility. Following a fire at the refinery, it has been shut down since 20 September 2022. Assets of \$731 million and associated liabilities of \$273 million were classified as held for sale in the group balance sheet at 31 December 2022. The sale completed on 28 February 2023.

Transactions that have been classified as held for sale during 2022, but were completed by 31 December 2022, are described below.

oil production & operations

On 12 June 2022, bp entered into an agreement to sell its 50% interest in the Sunrise oil sands project in Canada to Cenovus Energy Inc. for C\$600 million (Canadian dollars) cash (subject to customary closing adjustments), up to C\$600 million of contingent consideration expiring after two years and Cenovus's 35% position in the undeveloped Bay du Nord project offshore Canada. The transaction closed on 31 August 2022.

On 11 March 2022, bp and Eni signed an agreement to form Azule Energy, an independent incorporated 50:50 joint venture, through the combination of the two companies' Angolan businesses. The transaction closed on 1 August 2022 and, from that date, bp reported an equity accounted investment in Azule Energy. This investment was initially recognized at a fair value of \$4,922 million (net of deferred gain) and the transaction resulted in a non-taxable accounting gain of \$1,932 million and a deferred gain of the same amount that will be recognized over time as the Azule Energy assets are depreciated.

The assets held for sale balance at 31 December 2021 consisted of assets of \$1,009 million and associated liabilities of \$333 million relating to the agreement to establish Basra Energy Company (BECL) between bp and PetroChina, an incorporated entity, to own and manage the companies' interests in the Rumaila field in Iraq. The transaction closed on 1 June 2022 and bp now reports an equity accounted investment in BECL.

In addition, at 31 December 2021, \$595 million of bp's investment in Aker BP was classified as held for sale in the group's balance sheet as a result of Aker BP's proposed acquisition of Lundin Energy for consideration in cash and new Aker BP shares which resulted in bp's 27.9% interest in Aker BP being diluted to a 15.9% interest in the combined company following the completion of the acquisition. The transaction completed on 30 June 2022 and a gain of \$904 million was recognized.

The total assets and liabilities held for sale at 31 December 2022 and 2021, which are all in the gas & low carbon energy, oil production and operations and customers & products segments, are set out in the table below.

	\$ million	
	2022	2021
Property, plant and equipment	693	35
Goodwill	58	137
Investments in associates	—	632
Inventories	255	152
Cash	35	—
Trade and other receivables	201	696
Assets classified as held for sale	1,242	1,652
Trade and other payables	(256)	(238)
Lease liabilities	(14)	(74)
Provisions	(36)	(47)
Deferred tax liabilities	(15)	—
Liabilities directly associated with assets classified as held for sale	(321)	(359)

3. Business combinations and other significant transactions

Business combinations

The group undertook a number of business combinations during 2022. Total consideration paid in cash amounted to \$3,671 million, offset by cash acquired of \$141 million.

Archaea Energy

On 28 December 2022, bp acquired 100% of the issued common stock of Archaea Energy Inc. a leading producer of renewable natural gas (RNG) in the US, that was listed on the New York Stock Exchange.

The acquisition expands bp's presence in the US biogas industry, enhancing its ability to support customers' decarbonization goals and progressing its aim to reduce the average lifecycle carbon intensity of the energy products it sells.

The total cash consideration for the transaction, all paid at completion, was \$3,137 million.

The transaction has been accounted for as a business combination using the acquisition method. The provisional fair values of the identifiable assets and liabilities acquired, as at the date of acquisition, are shown in the table below. The intangible assets recognized are primarily the biogas rights agreements Archaea Energy has with landfill owners. The goodwill recognized reflects the part of the project development pipeline that did not qualify for separate recognition at the acquisition date and goodwill arising from recognition of deferred tax liabilities on fair value uplifts. The goodwill balance is not expected to be deductible for tax purposes.

The transaction included a step acquisition of the Mavrix LLC joint venture, which bp and Archaea Energy each held a 50% interest in prior to this transaction. The fair value of bp's interest in Mavrix LLC immediately before the acquisition date was \$373 million and the gain recognized in 'Interest and other income' as a result of remeasuring this interest to fair value was \$267 million.

	\$ million
	2022
Assets	
Property plant and equipment	885
Goodwill	409
Intangible assets	3,475
Investments in equity-accounted entities	917
Inventory	42
Trade and other receivables	67
Cash and cash equivalents	107
Liabilities	
Trade and other payables	(1,032)
Finance debt	(1,044)
Deferred tax liabilities	(293)
Provisions	(16)
Non-controlling interest	(7)
Total consideration	3,510
Of which:	
Cash	3,137
Fair value of previously held interest in Mavrix LLC	373

As the transaction completed shortly prior to the end of the reporting period, the acquisition-date fair values of the assets and liabilities acquired are provisional. As we gain further understanding of the acquired assets and development pipeline, these fair values may be subsequently adjusted, including goodwill.

An analysis of the cash flows relating to the acquisition included within the cash flow statement for the full year 2022 is provided below.

	\$ million
	2022
Transaction costs of the acquisition (included in cash flows from operating activities)	56
Cash consideration paid, net of cash acquired (included in cash flows from investing activities)	3,030
Total net cash outflow for the acquisition	3,086
Settlement of acquired debt and warrants liabilities immediately after completion (included in cash flows from financing activities)	1,044
Total net cash outflow related to the acquisition	4,130

The revenues and profit before tax generated by the acquired activities from the date of acquisition to 31 December 2022 were immaterial. If the business combination had taken place on 1 January 2022, it is estimated that the acquired activities would have generated revenues of \$370 million and losses before tax of \$169 million.

Other acquisitions

The fair value of the net assets (including goodwill) recognized from other business combinations in the full year was \$611 million. This principally related to the acquisitions of the Flat Ridge 2 onshore wind farm and EDF Energy Services in North America.

4. Disposals and impairment – continued

oil production & operations

In 2022 gains principally related to a gain of \$1,932 million arising from the contribution of bp's Angolan business to Azule Energy, a gain of \$904 million related to the deemed disposal of 12% of the group's interest in Aker BP, an associate of bp, following completion of Aker BP's acquisition of Lundin Energy, and \$349 million in relation to the disposal of the group's interest in the Rumaila field in Iraq to Basra Energy Company, an associate of bp.

Losses included \$479 million of accumulated exchange losses previously charged to equity and taken to the income statement as a result of the decision to exit bp's other businesses with Rosneft within Russia.

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.

customers & products

In 2022, gains principally relate to a gain of \$268 million arising from the divestment of our Swiss retail assets. In 2020, gains principally resulted from the \$2,300 million 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. In 2020, losses included \$229 million in relation to cessation of manufacturing operations at the Kwinana Refinery following the decision to cease fuel production.

other businesses and corporate

In 2022 the losses on disposal of businesses and fixed assets was \$11,082 million in respect of the decision to exit our holding in Rosneft which resulted in the reclassification to the income statement of \$10,372 million of accumulated exchange losses, a cash flow hedge reserve of \$651 million relating to the original acquisition of Rosneft shares and bp's cumulative share of Rosneft's other comprehensive income of \$59 million which were all previously charged to equity.

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 transactions categorized as a business disposal in 2022 were the formation of Azule Energy, the formation of Basra Energy Company and the sale of our 50% interest in the Sunrise oil sands project in Canada.

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.

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

	\$ million		
	2022	2021	2020
Non-current assets	3,681	1,620	9,092
Current assets	2,972	69	1,539
Non-current liabilities	(1,869)	(287)	(1,639)
Current liabilities	(1,074)	(3)	(782)
Total carrying amount of net assets disposed	3,710	1,399	8,210
Recycling of foreign exchange on disposal	(26)	35	(328)
Costs on disposal	488	(5)	13
	4,172	1,429	7,895
Gains (losses) on sale of businesses	6,219	1,632	2,570
Total consideration	10,391	3,061	10,465
Non-cash consideration	(8,999)	(108)	(219)
Consideration received (receivable)	449	2,859	(5,257)
Proceeds from the sale of businesses, net of cash disposed^a	1,841	5,812	4,989

^a Proceeds are stated net of cash and cash equivalents disposed of \$318 million (2021 \$2 million and 2020 \$101 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, goodwill and equity-accounted entities within Note 1. See also Note 12, and Note 15 for further information on impairments by asset category.

gas & low carbon energy

The 2022 impairment loss of \$745 million primarily relates to losses incurred in respect of certain assets in Mauritania & Senegal (\$729 million) and principally arose as a result of increased forecast future expenditure. The 2022 impairment reversal of \$1,333 million primarily relates to the Trinidad CGU (\$1,331 million) and principally arose as a result of changes to the group's oil and gas price assumptions. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2022 in total, based on their value in use, is \$9,609 million.

4. Disposals and impairment – continued

The 2021 impairment loss of \$834 million primarily relates to losses incurred in respect of certain assets 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.

oil production & operations

Impairment losses and reversals in all years relate primarily to producing assets and, in 2022, equity accounted investments.

The 2022 impairment loss of \$4,480 million primarily relates to impairment of the Pan American Energy Group S.L. joint venture as a result of expected portfolio changes (\$2,900 million) and the decision to exit bp's other businesses with Rosneft within Russia (\$1,043 million). The 2022 impairment reversal of \$893 million principally relates to changes in price and reserves assumptions in the North Sea (\$643 million). The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2022 in total, based on their value in use, is \$7,831 million.

The 2021 impairment loss of \$1,617 million principally relates to the decision to exit the Sunrise oil sands project in Canada (\$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.

customers & products

The 2022 impairment loss of \$1,874 million primarily relates to changes in economic assumptions in the Products business including the impairment of the Gelsenkirchen refinery in Germany (\$1,366 million), and announced portfolio changes. The recoverable amounts of the CGUs were based on value-in-use calculations. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2022 in total, based on their value in use, is \$1,648 million.

2021 impairment loss of \$962 million principally relates to announced portfolio changes in the products business (\$595 million).

2020 impairment loss of \$840 million 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

The 2022 impairment loss of \$13,536 million arises primarily a result of bp's decision to exit its shareholding in Rosneft (\$13,479 million, including \$528 million which relates to estimated earnings in the first two months of the year prior to the loss of significant influence). The recoverable amount of the CGU which comprises Rosneft is estimated to be \$nil.

Impairment losses totalling \$63 million and \$12 million were recognized in 2021 and 2020 respectively.

5. Segmental analysis

The group's organizational structure reflects the various activities in which bp is engaged as well as how performance and resource allocation is evaluated by the chief operating decision maker. At 31 December 2022, bp has three reportable segments: Gas & low carbon energy, Oil production & operations, and Customers & products. Each are managed separately, with decisions taken for the segment as a whole, and represent a single operating segment that does not result from aggregating two or more segments.

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.

Oil production & operations comprises regions with upstream activities that predominantly produce crude oil.

Customers & products comprises the group's customer-focused businesses, which includes convenience and retail fuels, EV charging, as well as Castrol, aviation and B2B and midstream. It also includes our products businesses, refining & oil trading, as well as our bioenergy businesses.

The group ceased to report Rosneft as a separate segment in the group's financial reporting for 2022 and its results are included in other businesses and corporate. See Note 1 - *Investment in Rosneft*. Comparative information for 2021 and 2020 has been restated to reflect the change in reportable segments.

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

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

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

5. Segmental analysis – continued

	\$ million					
						2022
By business	gas & low carbon energy	oil production & operations	customers & products	other businesses & corporate	Consolidation adjustment and eliminations	Total group
Segment revenues						
Sales and other operating revenues	56,255	33,193	188,623	2,299	(38,978)	241,392
Less: sales and other operating revenues between segments	(5,913)	(30,294)	(1,418)	(1,353)	38,978	–
Third party sales and other operating revenues	50,342	2,899	187,205	946	–	241,392
Earnings from joint ventures and associates – after interest and tax	148	1,609	248	525	–	2,530
Segment results						
Replacement cost profit (loss) before interest and taxation	14,696	19,721	8,869	(26,737)	139	16,688
Inventory holding gains (losses) ^a	(8)	(7)	1,366	–	–	1,351
Profit (loss) before interest and taxation	14,688	19,714	10,235	(26,737)	139	18,039
Finance costs						(2,703)
Net finance expense relating to pensions and other post-retirement benefits						69
Profit before taxation						15,405
Other income statement items						
Depreciation, depletion and amortization						
US	75	3,141	1,328	80	–	4,624
Non-US	4,933	2,423	1,542	796	–	9,694
Charges for provisions, net of write-back of unused provisions, including change in discount rate	(234)	213	3,955	143	–	4,077
Segment assets						
Investments in joint ventures and associates	5,299	11,370	3,875	57	–	20,601
Additions to non-current assets ^b	4,439	15,098	9,541	1,047	–	30,125

^a See explanation of inventory holding gains and losses on page 209.

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

5. Segmental analysis – continued

						\$ million
						2021
By business	gas & low carbon energy	oil production & operations	customers & products	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	2,612	–	3,999
Segment results						
Replacement cost profit (loss) before interest and taxation	2,133	10,501	2,208	(348)	(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	(89)	(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	14,424	–	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 209.

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

5. Segmental analysis – continued

						\$ million
						2020
By business	gas & low carbon energy	oil production & operations	customers & products	other businesses & corporate	Consolidation adjustment and eliminations	Total group
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	(245)	–	(403)
Segment results						
Replacement cost profit (loss) before interest and taxation	(7,068)	(14,583)	3,418	(728)	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	(817)	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	11,849	–	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 209.

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

	\$ million		
By geographical area	2022		
	US	Non-US	Total
Revenues			
Third party sales and other operating revenues ^a	71,118	170,274	241,392
Other income statement items			
Production and similar taxes	194	2,131	2,325
Non-current assets			
Non-current assets ^{b c}	60,237	89,144	149,381

^a Non-US region includes UK \$36,541 million

^b Non-US region includes UK \$24,813 million

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

	\$ million		
By geographical area	2021		
	US	Non-US	Total
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.

5. Segmental analysis – continued

	\$ million		
			2020
By geographical area	US	Non-US	Total
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.

6. Sales and other operating revenues

	\$ million		
	2022	2021	2020
Crude oil	6,309	5,483	5,048
Oil products	149,854	101,418	63,564
Natural gas, LNG and NGLs	41,770	24,378	10,762
Non-oil products and other revenues from contracts with customers	7,896	6,082	9,779
Revenue from contracts with customers	205,829	137,361	89,153
Other operating revenues ^a	35,563	20,378	16,791
Total sales and other operating revenues	241,392	157,739	105,944

^a Principally relates to commodity derivative transactions including sales of bp own production in trading books.

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

The group's sales to customers of crude oil and oil products were substantially all made by the 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.

7. Income statement analysis

	\$ million		
	2022	2021	2020
Interest and other income			
Interest income from			
Financial assets measured at amortized cost	371	221	215
Financial assets measured at fair value through profit or loss	59	5	25
Other income	673	355	423
	1,103	581	663
Currency exchange losses charged to the income statement ^a	160	345	38
Expenditure on research and development	274	266	332
Costs relating to the Gulf of Mexico oil spill (pre-interest and tax) ^b	84	70	255
Finance costs			
Interest expense on lease liabilities	245	288	337
Interest expense on other liabilities measured at amortized cost ^c	2,070	1,820	2,166
Capitalized at 3.56% (2021 2.63% and 2020 2.75%) ^d	(464)	(287)	(345)
Losses arising on finance debt risk management activities ^e	43	145	–
Unwinding of discount on provisions	369	391	437
Unwinding of discount on other payables measured at amortized cost	440	500	520
	2,703	2,857	3,115

^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 2022 includes a gain of \$37 million (2021 loss of \$195 million and 2020 loss of \$158 million) associated with the buyback of finance debt.

^d Tax relief on capitalized interest is approximately \$108 million (2021 \$66 million and 2020 \$83 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 period were not reclassified as the amounts were not material.

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

The following financial information represents the amounts included within the group totals relating to activity associated with the exploration for and evaluation of oil and natural gas resources. All such activity is recorded within the 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		
	2022	2021	2020
Exploration and evaluation costs			
Exploration expenditure written off ^a	385	167	9,920
Other exploration costs	200	257	360
Exploration expense for the year	585	424	10,280
Impairment losses	2	1	156
Intangible assets – exploration and appraisal expenditure ^b	4,213	4,289	4,113
Liabilities	88	98	71
Net assets	4,125	4,191	4,042
Cash used in operating activities	200	257	360
Cash used in investing activities	909	369	674

^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 Amount capitalized at 31 December 2022, 2021 and 2020 relates to assets in various regions. The largest of these is approximately \$600 million capitalized in the Middle East region (2021 approximately \$700 million and 2020 approximately \$700 million capitalized in the Middle East Region).

9. Taxation

Tax on profit

	\$ million		
	2022	2021	2020
Current tax			
Charge for the year	12,523	4,808	2,095
Adjustment in respect of prior years	145	138	50
	12,668	4,946	2,145
Deferred tax^a			
Origination and reversal of temporary differences in the current year	4,768	3,366	(7,826)
Adjustment in respect of prior years	(674)	(1,572)	1,522
	4,094	1,794	(6,304)
Tax charge (credit) on profit or loss	16,762	6,740	(4,159)

^a Origination and reversal of temporary differences in the current year include the impact of tax rate changes on deferred tax balances. 2022 includes a charge of \$1,834 million in respect of the introduction of the UK Energy Profits Levy. The adjustment 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, including changes to price assumptions and profit forecasts.

In 2022, the total tax charge recognized within other comprehensive income was \$266 million (2021 \$1,252 million charge and 2020 \$39 million charge). In 2022 this primarily comprises a release of deferred withholding tax on other comprehensive income movements relating to Rosneft. In 2021 and 2020 this primarily comprises the deferred tax impact of the remeasurements of the net pension and other post-retirement benefit liability or asset. See Note 32 for further information.

The total tax credit recognized directly in equity was \$214 million (2021 \$170 million charge and 2020 \$154 million charge). In 2022 and 2021 this mainly relates to transactions involving non-controlling interests and 2020 principally relates to a non-controlling interest transaction entered into by Rosneft.

9. Taxation – continued

Reconciliation of the effective tax rate

The following table provides a reconciliation of the group weighted average statutory corporate income tax rate to the effective tax rate of the group on profit or loss before taxation. For 2022 the items presented in the reconciliation are affected by the impacts of Rosneft. In order to provide a more meaningful analysis of the effective tax rate for 2022, the table also presents a separate reconciliation for the group excluding the impacts of Rosneft, and for the impacts of Rosneft in isolation.

	\$ million				
	2022 excluding impact of Rosneft	2022 impact of Rosneft ^a	2022	2021	2020
Profit (loss) before taxation	40,925	(25,520)	15,405	15,227	(24,888)
Tax charge (credit) on profit or loss ^b	17,823	(1,061)	16,762	6,740	(4,159)
Effective tax rate	44%	4%	109%	44%	17%
					%
Tax rate computed at the weighted average statutory rate ^c	42	20	77	54	31
Increase (decrease) resulting from					
Tax reported in equity-accounted entities ^d	(1)	–	(4)	(3)	–
Adjustments in respect of prior years	(1)	–	(3)	(9)	(6)
Deferred tax not recognized	(1)	–	(2)	8	(3)
Tax incentives for investment	–	–	(1)	(1)	1
Disposal impacts ^e	(3)	–	(8)	(4)	–
Foreign exchange	1	–	3	1	(1)
Items not deductible for tax purposes	2	–	5	1	(3)
Impact of bp's decision to exit its shareholding in Rosneft	–	(16)	27	–	–
Tax rate change effect of UK Energy Profits Levy ^f	4	–	12	–	–
Other	1	–	3	(3)	(2)
Effective tax rate	44	4	109	44	17

^a Includes the impact of bp's decision to exit its shareholding in Rosneft and its other businesses with Rosneft in Russia. See also Note 1 - Significant judgements and estimate: investment in Rosneft.

^b The tax credit regarding the impact of Rosneft relates to the release of deferred withholding tax on unremitted earnings.

^c 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. 2022 includes the higher North Sea tax rate as a result of the UK Energy Profits Levy.

^d Includes withholding tax in respect of distributions from equity-accounted entities.

^e 2022 primarily relates to the contribution of bp's Angolan business to Azule Energy and 2021 primarily relates to the divestment of a 20% stake in Oman Block 61.

^f 2022 comprises the deferred tax impact of the UK Energy Profits Levy on existing temporary differences.

Deferred tax

	\$ million	
Analysis of movements during the year in the net deferred tax (asset) liability	2022	2021
At 1 January	2,370	(913)
Exchange adjustments ^a	(334)	9
Charge for the year in the income statement	4,094	1,794
Charge for the year in other comprehensive income	272	1,302
Charge (credit) for the year in equity	(214)	170
Acquisitions and disposals ^b	430	8
At 31 December	6,618	2,370

^a 2022 primarily relates to the foreign currency retranslation effect on the deferred tax liability on pension plan surpluses in the UK.

^b 2022 primarily relates to the Archaea Energy acquisition and the contribution of bp's Angolan business to Azule Energy.

9. Taxation – continued

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

	\$ million				
	Income statement			Balance sheet	
	2022	2021	2020	2022	2021
Deferred tax liability					
Depreciation	1,863	899	(7,295)	18,025	16,276
Pension plan surpluses	42	105	69	3,022	3,898
Derivative financial instruments	(21)	(33)	33	–	24
Other taxable temporary differences ^a	(992)	180	(32)	1,000	1,782
	892	1,151	(7,225)	22,047	21,980
Deferred tax asset					
Depreciation	(309)	(846)	(849)	(1,974)	(1,678)
Lease liabilities	(8)	(43)	286	(1,047)	(1,128)
Pension plan and other post-retirement benefit plan deficits	47	119	2	(647)	(1,221)
Decommissioning, environmental and other provisions	770	(744)	438	(6,653)	(7,891)
Derivative financial instruments	(6)	(9)	–	(282)	(75)
Tax credits	1,578	1,282	310	(779)	(2,359)
Loss carry forward	1,536	1,064	543	(2,669)	(4,202)
Other deductible temporary differences ^b	(406)	(180)	191	(1,378)	(1,056)
	3,202	643	921	(15,429)	(19,610)
Net deferred tax charge (credit) and net deferred tax liability	4,094	1,794	(6,304)	6,618	2,370
Of which – deferred tax liabilities				10,526	8,780
– deferred tax assets				3,908	6,410

^a The 2022 income statement and 2021 balance sheet include amounts relating to deferred withholding tax on unremitted earnings of Rosneft. The 2022 balance sheet amount does not include any temporary differences that are individually significant in their nature.

^b The 2022 and 2021 balance sheet amounts do not include any temporary differences that are individually significant in their nature.

Of the \$3,908 million of deferred tax assets recognized on the group balance sheet at 31 December 2022 (2021 \$6,410 million), \$2,779 million (2021 \$6,342 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 (see Note 1 for further information) and for the UK, forecast profits associated with long-term LNG contracts, that indicate sufficient future taxable profits will be available to utilize such assets within any applicable expiry period. For 2022, this mainly includes \$1,333 million in the UK, \$505 million in Mauritania and \$370 million in Senegal (2021 mainly included \$2,224 million in the US, \$892 million in the UK, \$762 million in India and \$541 million in Angola).

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

At 31 December	\$ billion	
	2022	2021
Unused US state tax losses ^a	2.1	2.5
Unused tax losses – other jurisdictions ^b	5.4	6.0
Unused tax credits	28.6	28.2
of which – arising in the UK ^c	24.6	24.6
– arising in the US ^d	4.0	3.6
Deductible temporary differences ^e	22.7	49.0
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	0.7	0.7

^a For 2022 these losses expire in the period 2023-2042 with applicable tax rates ranging from 3% to 10%.

^b 2022 and 2021 mainly relate to the UK, Canada and Brazil. 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. 2022 includes \$0.7 billion in respect of Algeria. These amounts will be eliminated following the disposal of bp's interests in Algeria in February 2023.

^d The US unused tax credits predominantly comprise foreign tax credits. No deferred tax asset has been recognized on these tax credits as they are unlikely to have value in the future. For 2022 these tax credits expire in the period 2023-2032.

^e The majority comprises fixed asset temporary differences in overseas branches of UK entities and the reduction in the year mainly reflects the contribution of bp's Angolan business to Azule Energy. Substantially all of the temporary differences have no expiry date. 2022 includes \$2.0 billion in respect of Algeria. These amounts will be eliminated following the disposal of bp's interests in Algeria in February 2023.

Impact of previously unrecognized deferred tax or write-down of deferred tax assets on tax charge	\$ million		
	2022	2021	2020
Current tax benefit relating to the utilization of previously unrecognized deferred tax assets	492	331	46
Deferred tax benefit arising from the reversal of a previous write-down of deferred tax assets	–	773	11
Deferred tax benefit relating to the recognition of previously unrecognized deferred tax assets	792	820	–
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	–	29	1,622

10. Dividends

The quarterly dividend which is expected to be paid on 31 March 2023 in respect of the fourth quarter 2022 is 6.610 cents per ordinary share (\$0.39660 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 14 March 2023.

	Pence per share			Cents per share			\$ million		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Dividends announced and paid in cash									
Preference shares							1	2	1
Ordinary shares									
March	4.1595	3.7684	8.1558	5.460	5.250	10.500	1,068	1,063	2,102
June	4.3556	3.7118	8.3421	5.460	5.250	10.500	1,061	1,062	2,119
September	5.1684	3.9529	4.0433	6.006	5.460	5.250	1,140	1,100	1,059
December	4.9402	4.1045	3.9169	6.006	5.460	5.250	1,088	1,077	1,059
	18.6237	15.5376	24.4581	22.932	21.420	31.500	4,358	4,304	6,340
Dividend announced, paid in March 2023				6.61			1,188		

The amount of unclaimed dividends recognized as a liability in other payables at 31 December 2022 is \$69 million (2021 \$62 million).

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 2022 dividend expected to be paid on 31 March 2023.

The financial statements for the year ended 31 December 2022 do not reflect the dividend announced on 7 February 2023 and which is expected to be paid in March 2023; this will be treated as an appropriation of profit in the year ending 31 December 2023.

11. Earnings per share

	Cents per share		
	2022	2021	2020
Per ordinary share			
Basic earnings per share	(13.10)	37.57	(100.42)
Diluted earnings per share	(13.10)	37.33	(100.42)
	Dollars per share		
	2022	2021	2020
Per American Depositary Share (ADS) ^a			
Basic earnings per share	(0.79)	2.25	(6.03)
Diluted earnings per share	(0.79)	2.24	(6.03)

^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.

	\$ million		
	2022	2021	2020
Profit (loss) attributable to bp shareholders	(2,487)	7,565	(20,305)
Less: dividend requirements on preference shares	1	2	1
Profit (loss) for the year attributable to bp ordinary shareholders	(2,488)	7,563	(20,306)
	Shares thousand		
	2022	2021	2020
Basic weighted average number of ordinary shares ^a	18,987,936	20,128,862	20,221,514
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	—	131,526	—
Weighted average number of ordinary shares outstanding used to calculate diluted earnings per share	18,987,936	20,260,388	20,221,514
	Shares thousand		
	2022	2021	2020
Basic weighted average number of ordinary shares – ADS equivalent	3,164,656	3,354,810	3,370,252
Potential dilutive effect of ordinary shares (ADS equivalent) issuable under employee share-based payment plans	—	21,921	—
Weighted average number of ordinary shares (ADS equivalent) outstanding used to calculate diluted earnings per share	3,164,656	3,376,731	3,370,252

^a Excludes treasury shares. See Note 31 for further information.

11. Earnings per share – continued

The number of ordinary shares outstanding at 31 December 2022, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 17,974,112,648 (2021 19,642,221,041). Between 31 December 2022 and 17 February 2023, the latest practicable date before the completion of these financial statements, there was a net increase of 6,834,739 of ordinary shares primarily as a result of share issues in relation to employee share-based payment plans partially offset by share buy backs. For additional information on share buy backs see Note 31.

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 112-147.

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	2022		2021	
	Number of options ^a thousand	Weighted average exercise price \$	Number of options ^a thousand	Weighted average exercise price \$
Outstanding	564,079	4.00	590,961	4.26
Exercisable	342	4.99	1,080	4.73
Dilutive effect	83,204	n/a	3,588	n/a

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

^b At 31 December 2022 the quoted market price of one bp ordinary share was £4.75 (2021 £3.31).

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

Share plans	2022	2021
	Number of shares ^a thousand	Number of shares ^a thousand
Vesting		
Within one year	167,672	92,210
1 to 2 years	192,734	149,077
2 to 3 years	226,027	179,449
3 to 4 years	2,595	109,265
Over 4 years	173	928
	589,201	530,929
Dilutive effect	244,886	152,899

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

There has been a net increase of 20,346,389 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2022 and 17 February 2023.

12. 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 2022	3,713	1,245	208,034	44,037	2,231	3,033	10,241	272,534
Exchange adjustments	(184)	(30)	—	(599)	(83)	(14)	(590)	(1,500)
Additions	51	31	6,221	2,188	252	42	993	9,778
Acquisitions	1	40	—	998	—	37	3	1,079
Transfers from intangible assets	—	—	357	—	—	—	—	357
Reclassified as assets held for sale	(49)	—	(4,351)	(1,408)	—	—	—	(5,808)
Deletions and disposals	(19)	(336)	(31,977)	(554)	(180)	(22)	(558)	(33,646)
At 31 December 2022	3,513	950	178,284	44,662	2,220	3,076	10,089	242,794
Depreciation - owned PP&E								
At 1 January 2022	706	654	134,550	21,841	1,792	2,388	5,783	167,714
Exchange adjustments	(26)	(21)	—	(299)	(61)	(11)	(354)	(772)
Charge for the year	47	26	9,770	1,457	135	72	501	12,008
Impairment losses	6	14	1,251	1,487	—	4	336	3,098
Impairment reversals	—	—	(2,221)	(65)	—	(5)	—	(2,291)
Reclassified as assets held for sale	(18)	—	(3,972)	(1,164)	—	—	—	(5,154)
Deletions and disposals	(15)	(172)	(28,688)	(354)	(177)	(17)	(447)	(29,870)
At 31 December 2022	700	501	110,690	22,903	1,689	2,431	5,819	144,733
Owned PP&E - net book amount at 31 December 2022	2,813	449	67,594	21,759	531	645	4,270	98,061
Right-of-use assets - net book amount at 31 December 2022 ^b	—	1,157	17	926	7	2,333	3,543	7,983
Total PP&E - net book amount at 31 December 2022	2,813	1,606	67,611	22,685	538	2,978	7,813	106,044
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
Assets under construction included above								
At 31 December 2022								22,313
At 31 December 2021								19,704
Depreciation charge for the year on right-of-use assets								
2022		190	18	321	10	853	577	1,969
2021		209	27	279	10	844	613	1,982

^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 \$560 million (2021 \$203 million) of drilling rig right-of-use assets and \$2,208 million (2021 \$2,230 million) of shipping vessel right-of-use assets are included in Plant, machinery and equipment and Transportation respectively.

13. Capital commitments

Authorized future capital expenditure for property, plant and equipment (excluding right-of-use assets) by group companies for which contracts had been signed at 31 December 2022 amounted to \$9,381 million (2021 \$8,208 million, 2020 \$8,009 million). bp has contracted capital commitments amounting to \$1,764 million (2021 \$1,075 million, 2020 \$1,087 million) in relation to joint ventures and \$18 million (2021 \$126 million, 2020 \$183 million) in relation to associates.

14. Goodwill and impairment review of goodwill

	\$ million	
	2022	2021
Cost		
At 1 January	12,991	13,093
Exchange adjustments	(367)	(91)
Acquisitions and other additions	573	139
Reclassified as assets held for sale	(58)	(137)
Deletions and disposals	(562)	(13)
At 31 December	12,577	12,991
Impairment losses		
At 1 January	618	613
Exchange adjustments	(1)	(1)
Impairment losses for the year	—	7
Deletions and disposals	—	(1)
At 31 December	617	618
Net book amount at 31 December	11,960	12,373
Net book amount at 1 January	12,373	12,480

Impairment review of goodwill

	\$ million	
	2022	2021
Goodwill at 31 December		
gas & low carbon energy	2,232	2,147
oil production & operations	4,925	5,464
customers & products	4,740	4,697
other businesses & corporate	63	65
	11,960	12,373

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

	\$ million		\$ million	
	gas & low carbon energy		oil production & operations	
	2022	2021	2022	2021
Goodwill	2,232	2,147	4,925	5,464
Excess of recoverable amount over carrying amount	12,971	3,991	36,045	32,438

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. The increase in headroom for both segments relates to movements due to the passage of time and price impacts.

No impairment of the goodwill balances in either gas & low carbon energy or oil production & operations was recognized during 2022 (2021 \$nil).

14. 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 191 mmbob per year (2021 261 mmbob per year) and in the oil production and operations segment is 346 mmbob per year (2021 604 mmbob 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 25% by 2030 from its 2019 baseline is expected to be achieved through future active management, including divestments, 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 the oil production & operations segment is 16%, and 10% for the gas & low carbon energy segment (2021 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. 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 for the purposes of determining whether the goodwill balances 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.

It is estimated that a 27% (2021 33%) 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 an 18% (2021 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

	2022					2021				
	Castrol	US Fuels	European Fuels	Other	Total	Castrol	US Fuels	European Fuels	Other	Total
Goodwill	2,524	606	815	795	4,740	2,837	606	862	392	4,697

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

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. A pre-tax discount rate of 8% (2021 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 3.4% (2021 2.8%) growth rate.

15. Intangible assets

	\$ million						
	2022						
					2021		
	Exploration and appraisal expenditure ^a	Biogas rights agreements	Other intangibles	Total	Exploration and appraisal expenditure ^a	Other intangibles	Total
Cost							
At 1 January	14,311	—	6,152	20,463	14,417	5,622	20,039
Exchange adjustments	—	—	(216)	(216)	—	(137)	(137)
Acquisitions ^b	—	3,398	194	3,592	—	47	47
Additions	894	—	831	1,725	409	628	1,037
Transfers to property, plant and equipment	(357)	—	—	(357)	(38)	—	(38)
Reclassified as assets held for sale	(9)	—	(7)	(16)	—	—	—
Deletions and disposals	(2,268)	—	(137)	(2,405)	(477)	(8)	(485)
At 31 December	12,571	3,398	6,817	22,786	14,311	6,152	20,463
Amortization							
At 1 January	10,022	—	3,990	14,012	10,304	3,642	13,946
Exchange adjustments	—	—	(128)	(128)	—	(86)	(86)
Exploration expenditure written off	385	—	—	385	167	—	167
Charge for the year	—	—	491	491	—	427	427
Impairment losses	2	—	21	23	1	15	16
Impairment reversals	—	—	(3)	(3)	—	—	—
Reclassified as assets held for sale	(9)	—	(7)	(16)	—	—	—
Deletions and disposals	(2,042)	—	(136)	(2,178)	(450)	(8)	(458)
At 31 December	8,358	—	4,228	12,586	10,022	3,990	14,012
Net book amount at 31 December	4,213	3,398	2,589	10,200	4,289	2,162	6,451
Net book amount at 1 January	4,289	—	2,162	6,451	4,113	1,980	6,093

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

^b 2022 acquisitions primarily relates to the acquisition of Archaea Energy Inc. See Note 3.

16. 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	
	2022	2021	2020	2022	2021
Azule Energy	540	—	—	5,264	—
Pan American Energy Group	538	(217)	(208)	2,000	4,396
Other joint ventures	50	760	(94)	5,136	5,586
	1,128	543	(302)	12,400	9,982

The joint ventures that are material to the group at 31 December 2022 are Azule Energy, which was formed during 2022 and in which bp owns a 50% stake, and Pan American Energy Group S.L. in which bp also owns a 50% stake.

bp classifies its investments in Azule Energy Holdings Limited and Pan American Energy Group S.L. as joint ventures because, per the terms of the shareholders' agreements, bp has joint control over Azule Energy and Pan American Energy Group S.L.. Azule Energy Holdings Limited is based in Angola and its functional currency is USD. Pan American Energy Group S.L. is based in Argentina and its functional currency is USD.

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

The operational and financial information of Azule Energy Holdings Limited and Pan American Energy Group S.L. is based on preliminary operational and financial results of Azule Energy Holdings Limited for 2022 and Pan American Energy Group S.L. for 2022, 2021 and 2020. Actual results may differ from these amounts - immaterial adjustments to the 2021 and 2020 numbers for Pan America Energy Group S.L. below have been included in the 2022 and 2021 numbers respectively.

16. Investments in joint ventures – continued

	\$ million			
	Gross amount			
	2022		2021	2020
	Azule Energy	PAEG	PAEG	PAEG
Sales and other operating revenues	2,274	6,408	4,394	3,505
Profit (loss) before interest and taxation	1,460	1,560	806	(366)
Finance costs	218	376	262	250
Profit (loss) before taxation^a	1,242	1,184	544	(616)
Taxation ^b	162	108	978	(200)
Profit (loss) for the year	1,080	1,076	(434)	(416)
Other comprehensive income	–	–	–	–
Total comprehensive income	1,080	1,076	(434)	(416)
Non-current assets	22,218	14,598	14,206	
Current assets ^c	4,132	3,054	1,864	
Total assets	26,350	17,652	16,070	
Current liabilities ^d	2,594	1,996	2,034	
Non-current liabilities ^e	13,228	5,856	5,244	
Total liabilities	15,822	7,852	7,278	
Net assets	10,528	9,800	8,792	
Less: non-controlling interests	–	–	–	
	10,528	9,800	8,792	

^a Azule Energy includes depreciation and amortisation of \$1,145 million, interest income of \$11 million and interest expense of \$218 million. PAEG includes depreciation and amortisation of \$1,039 million (2021 \$930 million and 2020 \$937 million), interest income of \$29 million (2021 \$19 million and 2020 \$18 million) and interest expense of \$375 million (2021 \$262 million and 2020 \$250 million).

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

^c Azule Energy includes cash and cash equivalents of \$1,031 million. PAEG includes cash and cash equivalents of \$1,012 million (2021 \$893 million).

^d Azule Energy includes current financial liabilities of \$2,077 million. PAEG includes current financial liabilities of \$751 million (2021 \$767 million).

^e Azule Energy includes non-current financial liabilities of \$4,700 million. PAEG includes non-current financial liabilities of \$2,151 million (2021 \$2,132 million).

The group received dividends, net of withholding tax, of \$35 million from Pan American Energy Group S.L in 2022 (2021 \$nil and 2020 \$18 million).

The group received dividends, net of withholding tax of \$500 million from Azule Energy Holdings Limited in 2022.

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

	\$ million									
	bp share									
	2022				2021			2020		
	Azule Energy	PAEG	Other	Total	PAEG	Other	Total	PAEG	Other	Total
Sales and other operating revenues	1,137	3,204	9,770	14,111	2,197	9,048	11,245	1,753	8,793	10,545
Profit (loss) before interest and taxation	730	780	255	1,765	403	927	1,330	(183)	32	(151)
Finance costs	109	188	137	434	131	58	189	125	76	201
Profit (loss) before taxation	621	592	118	1,331	272	869	1,141	(308)	(44)	(352)
Taxation	81	54	67	202	489	107	596	(100)	49	(51)
Non-controlling interest	–	–	1	1	–	2	2	–	1	1
Profit (loss) for the year	540	538	50	1,128	(217)	760	543	(208)	(94)	(302)
Other comprehensive income	–	–	50	50	–	5	5	–	(5)	(5)
Total comprehensive income	540	538	100	1,178	(217)	765	548	(208)	(99)	(307)
Non-current assets	11,109	7,299	7,775	26,183	7,103	7,702	14,805			
Current assets	2,066	1,527	2,778	6,371	932	2,385	3,317			
Total assets	13,175	8,826	10,553	32,554	8,035	10,087	18,122			
Current liabilities	1,297	998	1,713	4,008	1,017	1,272	2,289			
Non-current liabilities	6,614	2,928	3,687	13,229	2,622	3,219	5,841			
Total liabilities	7,911	3,926	5,400	17,237	3,639	4,491	8,130			
Net assets	5,264	4,900	5,153	15,317	4,396	5,596	9,992			
Less: non-controlling interests	–	–	(13)	(13)	–	5	5			
	5,264	4,900	5,140	15,304	4,396	5,591	9,987			
Group investment in joint ventures										
Group share of net assets (as above)	5,264	4,900	5,140	15,304	4,396	5,591	9,987			
Impairment charge for the year	–	(2,900)	–	(2,900)	–	–	–			
Loans made by group companies to joint ventures	–	–	(4)	(4)	–	(5)	(5)			
	5,264	2,000	5,136	12,400	4,396	5,586	9,982			

16. Investments in joint ventures – continued

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

		\$ million					
Sales to joint ventures		2022		2021		2020	
Product	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December	
LNG, crude oil and oil products, natural gas	4,212	316	3,923	292	2,974	180	
Purchases from joint ventures		2022		2021		2020	
Product	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December	
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	1,893	574	716	93	959	84	

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.

The majority of sales to joint ventures in 2022 relate to heating oil, gasoline, diesel and lubricant product transactions with Mobene and Ocwen Energy. The majority of purchases from joint ventures in 2022 relate to crude oil and oil products transactions with Azule Energy.

The bp investment in Pan American Energy Group S.L. joint venture has been impaired in 2022 by \$2,900 million as a result of expected portfolio changes.

bp's share of net impairment charges recognized by joint ventures in 2022 was \$256 million (2021 reversals of \$214 million) of which \$276 million charge (2021 \$nil) was in the gas and low carbon energy segment and \$20 million reversals (2021 reversals of \$214 million) was in the oil production & operations segment.

17. Investments in associates

The following table provides aggregated summarized financial information for the group's associates as it relates to the amounts recognized in the group income statement and on the group balance sheet. There were no individually material associates to the Group at 31 December 2022. The associate which was material to the Group at both 31 December 2021 and 2020 was 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. On 27 February 2022, bp announced it would exit its shareholding in Rosneft and bp's two nominated Rosneft directors both stepped down from Rosneft's board. As a result, the significant judgement on significant influence over Rosneft was reassessed and a new significant estimate was identified for the fair value of bp's equity investment in Rosneft. From that date, bp accounts for its interest in Rosneft as a financial asset measured at fair value within 'Other investments'. The total pre-tax charge during the year-ended 31 December 2022 relating to bp's investment in Rosneft is \$24,561 million consisting of \$11,082 million included in losses on disposal, primarily relating to the recycling to the income statement of accumulated exchange losses, and a \$13,479 million impairment charge including \$528 million which relates to estimated earnings in the first two months of the year prior to the loss of significant influence. For further information see Note 1 - *Investment in Rosneft* and Note 4 Disposals and impairment. As a result of bp's decision to exit its other businesses with Rosneft in Russia, which were primarily accounted for as investments in associates, an additional impairment charge of \$1,043 million including \$35 million which relates to estimated earnings in the first two months of the year and accumulated exchange losses of \$479 million previously charged to equity have been taken to the income statement. The total pre-tax charge in 2022 relating to bp's investment in Rosneft and other businesses with Rosneft in Russia is \$25,520 million.

		\$ million					
		Income statement			Balance sheet		
		Earnings from associates - after interest and tax			Investments in associates		
		2022	2021	2020	2022	2021	2020
Rosneft ^a		528	2,694	(229)	—	14,354	
Other associates		874	762	128	8,201	6,647	
		1,402	3,456	(101)	8,201	21,001	

^a See also Note 1 – Significant judgements and estimate: investment in Rosneft.

The group recognized dividends, net of withholding tax, of \$nil from Rosneft in 2022 (2021 \$640 million and 2020 \$480 million).

17. Investments in associates – continued

The following table provides summarized financial information relating to Rosneft for 2021 and 2020. 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 adjusted 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	
	2021	2020
Sales and other operating revenues	118,755	82,786
Profit before interest and taxation	18,537	1,270
Finance costs	1,357	1,742
Profit (loss) before taxation	17,180	(472)
Taxation	3,209	208
Non-controlling interests	1,743	482
Profit (loss) for the year	12,228	(1,162)
Other comprehensive income	54	1,653
Total comprehensive income	12,282	491
Non-current assets	155,898	
Current assets	45,790	
Total assets	201,688	
Current liabilities	47,061	
Non-current liabilities	78,117	
Total liabilities	125,178	
Net assets	76,510	
Less: non-controlling interests	11,357	
	65,153	

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

	\$ million						
	2022	2021			2020		
		Total	Rosneft	Other	Total	Rosneft	Other
Sales and other operating revenues	14,841	26,163	10,005	36,168	17,535	5,946	23,481
Profit before interest and taxation	3,053	4,084	1,602	5,686	295	276	571
Finance costs	73	299	73	372	372	80	452
Profit (loss) before taxation	2,980	3,785	1,529	5,314	(77)	196	119
Taxation	1,498	707	767	1,474	51	67	118
Non-controlling interests	80	384	—	384	101	1	102
Profit (loss) for the year	1,402	2,694	762	3,456	(229)	128	(101)
Other comprehensive income	352	12	27	39	336	(19)	317
Total comprehensive income	1,754	2,706	789	3,495	107	109	216
Non-current assets	11,993	34,346	9,259	43,605			
Current assets	3,368	10,088	2,418	12,506			
Total assets	15,361	44,434	11,677	56,111			
Current liabilities	2,936	10,368	1,876	12,244			
Non-current liabilities	4,255	17,210	3,298	20,508			
Total liabilities	7,191	27,578	5,174	32,752			
Net assets	8,170	16,856	6,503	23,359			
Less: non-controlling interests	—	2,502	—	2,502			
	8,170	14,354	6,503	20,857			
Group investment in associates							
Group share of net assets (as above)	8,170	14,354	6,503	20,857			
Loans made by group companies to associates	31	—	144	144			
	8,201	14,354	6,647	21,001			

17. Investments in associates – continued

Transactions between the group and its associates are summarized below.

		2022		2021		2020	
		Amount receivable at 31 December		Amount receivable at 31 December		Amount receivable at 31 December	
Product	Sales			Sales		Sales	
LNG, crude oil and oil products, natural gas	1,042	417		852	201	855	169

		2022		2021		2020	
		Amount payable at 31 December		Amount payable at 31 December		Amount payable at 31 December	
Product	Purchases			Purchases		Purchases	
Crude oil and oil products, natural gas, transportation tariff	6,199	2,086		7,683	2,072	4,926	1,280

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 in 2022 relate to crude oil and oil products transactions with Aker BP. The majority of purchases from associates in 2021 relate to crude oil and oil products transactions with Rosneft. Sales to associates are related to various entities.

bp has commitments amounting to \$8,488 million (2021 \$9,930 million), primarily in relation to contracts with its associates for the purchase of transportation capacity. For information on capital commitments in relation to associates see Note 13.

bp's share of impairment charges taken by associates in 2022 was \$nil (2021 \$291 million).

18. Other investments

		2022		2021	
		Current	Non-current	Current	Non-current
Equity investments ^a		—	1,040	—	717
Contingent consideration		364	1,522	237	1,680
Other		214	108	43	147
		578	2,670	280	2,544

^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.

19. Inventories

		2022		2021	
Crude oil		3,608		3,259	
Natural gas		825		474	
Emissions allowances		436		290	
Refined petroleum and petrochemical products		7,920		6,638	
		12,789		10,661	
Trading inventories		14,004		11,525	
		26,793		22,186	
Supplies		1,288		1,525	
		28,081		23,711	
Cost of inventories expensed in the income statement		141,043		92,923	

The inventory valuation at 31 December 2022 is stated net of a provision of \$483 million (2021 \$432 million) to write down inventories to their net realizable value, of which \$195 million (2021 \$64 million) relates to hydrocarbon inventories. The net charge to the income statement in the year in respect of inventory net realizable value provisions was \$199 million (2021 \$153 million credit), of which \$195 million charge (2021 \$151 million credit) related to hydrocarbon inventories.

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

20. Trade and other receivables

	\$ million			
	2022		2021	
	Current	Non-current	Current	Non-current
Financial assets				
Trade receivables	28,229	12	22,307	17
Amounts receivable from joint ventures and associates	654	79	404	89
Receivables related to disposals ^a	191	194	205	823
Other receivables	3,762	414	2,874	472
	32,836	699	25,790	1,401
Non-financial assets				
Sales taxes and production taxes	1,037	379	1,131	474
Other receivables	137	14	218	818
	1,174	393	1,349	1,292
	34,010	1,092	27,139	2,693

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

In both 2022 and 2021 the group entered into non-recourse arrangements to discount certain receivables in support of supply and trading activities and the management of credit risk.

Trade and other receivables are predominantly non-interest bearing.

See Note 29 for further information.

21. Valuation and qualifying accounts

	\$ million					
	2022		2021		2020	
	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments
At 1 January	584	169	555	186	509	249
Charged to costs and expenses	143	17,471	136	3	214	103
Charged to other accounts ^a	(8)	(27)	(11)	—	2	—
Deductions	(83)	(41)	(96)	(20)	(170)	(166)
Reclassifications	—	(14,522)	—	—	—	—
At 31 December	636	3,050	584	169	555	186

^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 \$513 million (2021 \$456 million, 2020 \$456 million) relating to receivables that were credit-impaired at the end of the year and \$123 million (2021 \$128 million, 2020 \$99 million) relating to receivables that were not credit-impaired at the end of the year.

Valuation and qualifying accounts relating to fixed asset investments comprise impairment provisions for investments in equity-accounted entities. The amount charged to costs and expenses in the year principally relates to bp's investments in Rosneft and The Pan American Energy Group S.L.. Amounts related to bp's investments in Rosneft and other businesses with Rosneft within Russia were reclassified following bp's loss of significant influence. See Note 1 - Investment in Rosneft, Note 4 Disposals and impairment, Note 16 Investments in joint ventures and Note 17 Investments in associates.

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 29.

22. Trade and other payables

	\$ million			
	2022		2021	
	Current	Non-current	Current	Non-current
Financial liabilities				
Trade payables	47,210	—	37,327	—
Amounts payable to joint ventures and associates	2,660	—	2,165	—
Payables for capital expenditure and acquisitions	2,579	446	2,063	764
Payables related to the Gulf of Mexico oil spill	1,213	8,350	1,276	9,154
Other payables	5,995	1,133	5,736	175
	59,657	9,929	48,567	10,093
Non-financial liabilities				
Sales taxes, customs duties, production taxes and social security	2,361	124	2,708	77
Other payables	1,966	334	1,336	397
	4,327	458	4,044	474
	63,984	10,387	52,611	10,567

Materially all of bp's trade payables have payment terms in the range of 30 to 60 days and give rise to operating cash flows.

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

Payables related to the Gulf of Mexico oil spill include amounts payable under the 2016 consent decree and settlement agreement with the United States and five Gulf coast states, including amounts payable for natural resource damages, state claims and Clean Water Act penalties. On a discounted basis the amounts included in payables related to the Gulf of Mexico oil spill for these elements of the agreements are \$4,146 million payable over 10 years, \$2,263 million payable over 11 years and \$3,065 million payable over 10 years respectively at 31 December 2022. Reported within net cash provided by operating activities in the group cash flow statement is a net cash outflow of \$1,370 million (2021 outflow of \$1,484 million, 2020 outflow of \$1,786 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 2022 also include amounts payable for settled economic loss and property damage claims which are payable over a period of up to five years.

23. Provisions

	\$ million					
	Decommissioning	Environmental	Litigation and claims	Emissions	Other	Total
At 1 January 2021	16,665	1,745	834	3,753	1,831	24,828
Exchange adjustments	(286)	(15)	(3)	(64)	(83)	(451)
Acquisitions	33	—	—	—	—	33
New and increase in existing provisions ^a	1,215	502	241	3,695	223	5,876
Write-back of unused provisions ^a	(9)	(89)	(53)	(40)	(174)	(365)
Unwinding of discount ^b	310	35	14	—	10	369
Change in discount rate	(3,245)	(134)	(81)	—	(13)	(3,473)
Utilization	(44)	(314)	(171)	(2,282)	(321)	(3,132)
Reclassified to other payables	(369)	(3)	—	—	(5)	(377)
Reclassified as liabilities directly associated with assets held for sale	(32)	(3)	—	—	(1)	(36)
Deletions	(1,895)	(3)	(2)	—	(48)	(1,948)
At 31 December 2022	12,343	1,721	779	5,062	1,419	21,324
Of which – current	577	390	191	4,643	531	6,332
– non-current	11,766	1,331	588	419	888	14,992

^a Recognized in the Group income statement, other than changes in decommissioning provisions related to owned assets.

^b Recognized in the Group income statement.

The decommissioning provision primarily 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 7, 22, 29, 33. 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.

24. Pensions and other post-retirement benefits

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

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

The 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 chair 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.

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 2022 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 date of hire, 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 2022 the aggregate level of contributions was \$74 million (2021 \$274 million and 2020 \$325 million). The aggregate level of contributions in 2023 is expected to be approximately \$150 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 2022. The closure of the defined benefit plan to future accrual eliminated the need for funding in 2022 and 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 US pension plan in 2022 and no statutory funding requirement is expected in the next 12 months.

The surplus relating to the US pension 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 2022.

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 2022. 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.

24. Pensions and other post-retirement benefits – continued

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

Financial assumptions used to determine benefit obligation ^a	UK			US			Eurozone		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Discount rate for plan liabilities	5.0	1.8	1.4	5.2	2.7	2.2	4.2	1.3	1.0
Rate of increase for pensions in payment	2.9	3.2	2.8	—	—	—	1.8	1.4	1.3
Rate of increase in deferred pensions	2.9	3.2	2.8	—	—	—	0.6	0.4	0.5
Inflation for plan liabilities	3.1	3.3	2.9	2.0	2.1	1.7	2.1	1.6	1.5

Financial assumptions used to determine benefit expense	UK			US			Eurozone		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Discount rate for plan service cost ^b	N/A	1.5	2.1	2.8	2.4	3.2	1.7	1.4	1.8
Discount rate for plan other finance expense ^c	1.8	1.7	2.1	2.7	2.2	3.1	1.3	1.0	1.3
Inflation for plan service cost ^b	N/A	2.8	2.6	2.1	1.7	1.5	1.6	1.5	1.7

^a Salary growth has not been a material financial assumption for the Group following the closure of the primary pension plan to future accrual in 2021. The rate of increase in salaries for the UK was 3.6% in 2020.

^b UK discount rate and inflation rate assumptions are not significant in determining the benefit expense following the closure of the primary UK plan to future accrual in 2021. Rates for the remaining small worldwide plan administered/reported through the UK are 2.5% and 2.2% respectively.

^c The discount rate for plan other finance expense in 2021 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.

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

Mortality assumptions	UK			US			Eurozone		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Life expectancy at age 60 for a male currently aged 60	26.9	26.9	26.9	25.0	24.9	24.7	26.0	25.8	25.7
Life expectancy at age 60 for a male currently aged 40	28.5	28.4	28.4	26.6	26.6	26.4	28.5	28.3	28.2
Life expectancy at age 60 for a female currently aged 60	28.8	28.9	28.8	28.0	27.9	27.7	29.3	29.1	29.0
Life expectancy at age 60 for a female currently aged 40	30.6	30.5	30.4	29.5	29.4	29.2	31.4	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 2022, the asset allocation policies of the UK and the US plans switched 2% and 3% of plan assets respectively from equities to bonds (2021 5% and 13% respectively).

The current asset allocation policy for the major plans at 31 December 2022 was as follows:

Asset category	UK	US
	%	%
Total equity (including private equity)	10	24
Bonds/cash (including LDI)	83	76
Property/real estate	7	—

24. Pensions and other post-retirement benefits – continued

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2022 were \$3,981 million (2021 \$7,399 million) of government-issued nominal bonds and \$11,945 million (2021 \$24,516 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 232.

	\$ million				
	UK ^a	US ^b	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2022					
Listed equities – developed markets	1,252	127	299	213	1,891
– emerging markets	117	17	48	71	253
Private equity ^c	2,715	1,126	–	2	3,843
Government issued nominal bonds ^d	4,039	1,370	682	263	6,354
Government issued index-linked bonds ^d	11,945	–	79	–	12,024
Corporate bonds ^d	6,317	2,569	563	146	9,595
Property ^e	2,297	–	89	18	2,404
Cash	567	175	61	116	919
Other ^f	1,088	33	56	357	1,534
Debt (repurchase agreements) used to fund liability driven investments	(5,290)	–	–	–	(5,290)
	25,047	5,417	1,877	1,186	33,527
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

^a Bonds held by the UK pension plans are denominated in sterling or hedged back to sterling to minimize foreign currency exposure. 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 or hedged back to USD to minimize foreign currency exposure.

^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 predominantly valued using observable market data based inputs other than quoted market 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.

^f Other includes insurance policies arising from annuity buy-in in Canada amounting to \$341 million.

24. Pensions and other post-retirement benefits – continued

	\$ million				
	2022				
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost ^a	41	219	87	25	372
Past service cost ^b	23	–	(1)	(21)	1
Settlement ^b	(8)	–	–	(4)	(12)
Operating charge (credit) relating to defined benefit plans	56	219	86	–	361
Payments to defined contribution plans	110	132	6	36	284
Total operating charge (credit)	166	351	92	36	645
Interest income on plan assets ^a	(694)	(189)	(34)	(44)	(961)
Interest on plan liabilities	529	217	85	61	892
Other finance (income) expense	(165)	28	51	17	(69)
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	(12,955)	(1,581)	(507)	(151)	(15,194)
Change in financial assumptions underlying the present value of the plan liabilities	11,531	2,195	1,903	221	15,850
Change in demographic assumptions underlying the present value of the plan liabilities	47	–	(14)	(15)	18
Experience gains and losses arising on the plan liabilities	(146)	(15)	(159)	(14)	(334)
Remeasurements recognized in other comprehensive income	(1,523)	599	1,223	41	340
Movements in benefit obligation during the year					
Benefit obligation at 1 January	32,834	8,273	7,108	1,652	49,867
Exchange adjustments	(3,224)	–	(443)	(68)	(3,735)
Operating charge relating to defined benefit plans	56	219	86	–	361
Interest cost	529	217	85	61	892
Contributions by plan participants	9	–	2	4	15
Benefit payments (funded plans) ^c	(1,211)	(364)	(78)	(79)	(1,732)
Benefit payments (unfunded plans) ^c	(7)	(285)	(229)	(23)	(544)
Reclassified as assets held for sale	–	–	–	(12)	(12)
Disposals	(74)	–	(2)	–	(76)
Remeasurements	(11,432)	(2,180)	(1,730)	(192)	(15,534)
Benefit obligation at 31 December^{a,d}	17,480	5,880	4,799	1,343	29,502
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	42,844	7,173	2,537	1,412	53,966
Exchange adjustments	(4,258)	–	(156)	(52)	(4,466)
Interest income on plan assets ^{a,e}	694	189	34	44	961
Contributions by plan participants	9	–	2	4	15
Contributions by employers (funded plans)	10	–	45	19	74
Benefit payments (funded plans) ^c	(1,211)	(364)	(78)	(79)	(1,732)
Reclassified as assets held for sale	–	–	–	(11)	(11)
Disposals	(86)	–	–	–	(86)
Remeasurements ^e	(12,955)	(1,581)	(507)	(151)	(15,194)
Fair value of plan assets at 31 December ^f	25,047	5,417	1,877	1,186	33,527
Surplus (deficit) at 31 December	7,567	(463)	(2,922)	(157)	4,025
Represented by					
Asset recognized	7,716	1,227	256	70	9,269
Liability recognized	(149)	(1,690)	(3,178)	(227)	(5,244)
	7,567	(463)	(2,922)	(157)	4,025
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	7,716	1,227	238	39	9,220
Unfunded	(149)	(1,690)	(3,160)	(196)	(5,195)
	7,567	(463)	(2,922)	(157)	4,025
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(17,331)	(4,190)	(1,639)	(1,147)	(24,307)
Unfunded	(149)	(1,690)	(3,160)	(196)	(5,195)
	(17,480)	(5,880)	(4,799)	(1,343)	(29,502)

^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. Following the closure of the primary UK pension plan to future accrual, current service cost in the UK consists of \$30 million of costs of administering that plan and \$11 million of current service cost from the remaining small worldwide plans administered and reported through the UK.

^b Past service costs predominantly represent largely offsetting income and costs due to the removal of some benefits for members in Turkish plans and their replacement with new arrangements administered and reported through the UK. Settlements reflect costs associated with buyouts in Canada and in certain other small worldwide plans administered and reported through the UK.

^c The benefit payments amount shown above comprises \$2,217 million benefits and \$8 million settlements, plus \$51 million of plan expenses incurred in the administration of the benefit.

^d The benefit obligation for the US is made up of \$4,411 million for pension liabilities and \$1,469 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes \$2,992 million for pension liabilities in Germany which is largely unfunded.

^e 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.

^f The fair value of plan assets includes borrowings related to the LDI programme as described on page 230.

24. Pensions and other post-retirement benefits – continued

					\$ million
					2021
	UK	US	Eurozone	Other	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 relating to defined benefit plans	(148)	246	74	32	204
Payments to defined contribution plans	76	136	7	36	255
Total operating charge	(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 ^d	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. For active members of that plan on 30 June 2021, benefits payable are now linked to salary as at that date. 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 230.

24. Pensions and other post-retirement benefits – continued

	\$ million				
	2020				
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost ^a	250	292	103	38	683
Past service cost ^b	(48)	(66)	12	(20)	(122)
Settlement	–	(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

^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 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.

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 2022 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 2023 comprise the total of current service cost and net finance income or expense.

	\$ million					
	UK		US		Eurozone	
	Increase	Decrease	Increase	Decrease	Increase	Decrease
Discount rate^a						
Effect on expense in 2023	(200)	179	(42)	48	(9)	5
Effect on obligation at 31 December 2022	(2,043)	2,552	(480)	686	(512)	616
Inflation rate^b						
Effect on expense in 2023	82	(77)	7	(6)	31	(28)
Effect on obligation at 31 December 2022	1,646	(1,531)	39	(34)	506	(441)

^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 2023	25	4	9
Effect on obligation at 31 December 2022	504	68	182

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, and the weighted average duration of the defined benefit obligations at 31 December 2022 are as follows:

	\$ million				
	UK	US	Eurozone	Other	Total
Estimated future benefit payments					
2023	985	497	307	95	1,884
2024	1,016	473	301	90	1,880
2025	1,022	477	307	90	1,896
2026	1,035	468	297	90	1,890
2027	1,048	470	293	90	1,901
2028-2032	5,371	2,283	1,376	459	9,489
	Years				
Weighted average duration	13.0	9.8	12.0	10.8	

25. Cash and cash equivalents

	\$ million	
	2022	2021
Cash	15,008	9,101
Triparty repos and term bank deposits	7,971	15,655
Cash equivalents (excluding triparty repos and term bank deposits)	6,216	5,925
	29,195	30,681

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; deposits and triparty repos of three months or less with banks and similar institutions; money market funds and treasury bills. The carrying amounts of cash, triparty repos, term bank deposits and treasury bills 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 2022 includes \$5,866 million (2021 \$4,740 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 \$5,822 million (2021 \$4,668 million) of cash and cash equivalents outside the UK and it is not expected that any significant tax will arise on repatriation.

26. Finance debt

	\$ million					
	2022			2021		
	Current	Non-current	Total	Current	Non-current	Total
Borrowings	3,198	43,746	46,944	5,557	55,619	61,176

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 \$2,297 million (2021 \$3,366 million) and issued commercial paper of \$725 million (2021 \$2,163 million). Finance debt does not include accrued interest of \$409 million (2021 \$484 million), which is reported within other payables. As part of actively managing its debt portfolio, during the year the group bought back \$7.4 billion (2021 \$11.0 billion equivalent) of finance debt consisting entirely of US dollar bonds. Derivatives associated with non-US dollar debt bought back in 2021 were also terminated. These transactions have no significant impact on net debt or gearing.

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

	Fixed rate debt			Floating rate debt		Total
	Weighted average interest rate %	Weighted average time for which rate is fixed Years	Amount \$ million	Weighted average interest rate %	Amount \$ million	Amount \$ million
	2022					
US dollar	3	14	28,651	6	18,105	46,756
Other currencies	6	8	188	—	—	188
			28,839		18,105	46,944
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

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 2022, 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			
	2022		2021	
	Fair value	Carrying amount	Fair value	Carrying amount
Short-term borrowings	901	901	2,191	2,191
Long-term borrowings	41,689	46,043	60,755	58,985
Total finance debt	42,590	46,944	62,946	61,176

27. Capital disclosures and net debt

The group defines capital as total equity plus net debt. Our financial framework seeks to support the pursuit of value growth for shareholders while maintaining a secure financial base.

The group monitors capital on the basis of gearing, that is, the ratio of net debt to the total of net debt plus total 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 2022, gearing was 20.5% (2021 25.3%).

	\$ million	
At 31 December	2022	2021
Finance debt	46,944	61,176
Less: fair value asset (liability) of hedges related to finance debt ^a	(3,673)	(118)
	50,617	61,294
Less: cash and cash equivalents	29,195	30,681
Net debt	21,422	30,613
Total equity	82,990	90,439
Gearing	20.5%	25.3%

^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 \$91 million (2021 liability of \$166 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 2022	61,176	481	8,611	250	70,518
Exchange adjustments	(164)	—	(260)	1	(423)
Net financing cash flow	(10,855)	(192)	(1,961)	(29)	(13,037)
Fair value (gains) losses	(3,694)	5,023	—	—	1,329
New and remeasured leases/joint operation payables	—	—	2,367	21	2,388
Other movements ^b	481	—	(208)	(201)	72
At 31 December 2022	46,944	5,312	8,549	42	60,847
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 operations payables	—	—	1,767	23	1,790
Other movements	(150)	10	(121)	—	(261)
At 31 December 2021	61,176	481	8,611	250	70,518

^a Currency swaps include cross currency interest rate swaps.

^b Other movements in finance debt include \$1,044 million acquired with Archaea Energy Inc. and a non-cash reduction in balances related to the Alaska divestment. Other movements in the net partner payable for leases entered into on behalf of joint operations primarily represent transfers to amounts held for sale.

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 30. When hedge accounting is applied to these derivatives they are included in the calculation of net debt shown above.

In addition to the liabilities included in the table above the group has accrued \$497 million (2021 \$nil) at the balance sheet date for shares repurchased between the end of the reporting period and 3rd February 2023. \$9,996 million is included in the group cash flow statement for the cash used to repurchase shares during the year.

28. 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 7 years (2021 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	
	2022	2021
Undiscounted lease liability cash flows due:		
Within 1 year	2,348	1,949
1 to 2 years	1,728	1,631
2 to 3 years	1,232	1,207
3 to 4 years	740	1,005
4 to 5 years	632	682
5 to 10 years	1,909	2,089
Over 10 years	1,275	1,462
	9,864	10,025
Impact of discounting	(1,315)	(1,414)
Lease liabilities at 31 December	8,549	8,611
Of which – current	2,102	1,747
– non-current	6,447	6,864

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 2022 is \$5,360 million (2021 \$4,996 million). The majority of this future commitment relates to the floating LNG vessel to service the Greater Tortue Ahmeyim project from 2023.

	\$ million	
	2022	2021
Total cash outflow for amounts included in lease liabilities ^a	2,200	2,372
Expense for variable payments not included in the lease liability ^a	27	37
Short-term lease expense ^a	482	409
Additions to right-of-use assets in the period	2,451	1,807
Gain (loss) on sale and leaseback transactions	–	(1)

^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 12. An analysis of lease interest expense is provided in Note 7.

29. Financial instruments and financial risk factors

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

		\$ million			
At 31 December 2022	Note	Measured at amortized cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
Financial assets					
Other investments	18	26	3,222	–	3,248
Loans		1,245	341	–	1,586
Trade and other receivables	20	33,535	–	–	33,535
Derivative financial instruments	30	–	24,395	–	24,395
Cash and cash equivalents	25	25,611	3,584	–	29,195
Financial liabilities					
Trade and other payables	22	(69,586)	–	–	(69,586)
Derivative financial instruments	30	–	(22,481)	(3,674)	(26,155)
Accruals		(7,631)	–	–	(7,631)
Lease liabilities	28	(8,549)	–	–	(8,549)
Finance debt	26	(46,944)	–	–	(46,944)
		(72,293)	9,061	(3,674)	(66,906)

29. Financial instruments and financial risk factors – continued

					\$ 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	18	–	2,824	–	2,824
Loans		1,045	232	–	1,277
Trade and other receivables	20	27,191	–	–	27,191
Derivative financial instruments	30	–	12,402	348	12,750
Cash and cash equivalents	25	27,107	3,574	–	30,681
Financial liabilities					
Trade and other payables	22	(58,660)	–	–	(58,660)
Derivative financial instruments	30	–	(13,456)	(465)	(13,921)
Accruals		(6,606)	–	–	(6,606)
Lease liabilities	28	(8,611)	–	–	(8,611)
Finance debt	26	(61,176)	–	–	(61,176)
		(79,710)	5,576	(117)	(74,251)

The fair value of finance debt is shown in Note 26. For all other financial instruments within the scope of IFRS 9, the carrying amount is either the fair value, or approximates the fair value.

Information on gains and losses on derivative financial assets and financial liabilities classified as measured at fair value through profit or loss is provided in the derivative gains and losses section of Note 30. Fair value gains and losses related to other assets and liabilities classified as measured at fair value through profit or loss totalled a net loss of \$238 million (2021 net gain of \$627 million). Dividend income of \$14 million (2021 \$11 million) from investments in equity instruments classified as measured at fair value through profit or loss is presented within other income.

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

Financial risk factors

The group is exposed to a number of different financial risks arising from ordinary 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 has developed a control framework aimed at managing the volatility inherent in certain of its ordinary 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, 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

29. 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 2022 was \$63 million (2021 \$100 million) whereas the average value-at-risk measure for the period was \$89 million (2021 \$64 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 coordinates 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 2022, the total foreign currency borrowings not swapped into US dollars amounted to \$188 million (2021 \$211 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 2022 the most significant open contracts in place were for \$5 million sterling (2021 \$55 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 2022 was 39% of total finance debt outstanding (2021 41%). The weighted average interest rate on finance debt at 31 December 2022 was 4% (2021 3%) and the weighted average maturity of fixed rate debt was fourteen years (2021 twelve years).

The group's earnings are sensitive to changes in interest rates on the element of the group's finance debt that is contractually floating rate or 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 2023, it is estimated that the group's finance costs for 2023 would change by approximately \$181 million (2021 \$251 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 mostly switched to the new risk free rates increasing 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 2022, bp's internal working group for IBOR reform continued to monitor market developments and manage the 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. As at 31 December 2022 finance debt with a carrying value of \$1,873 million (2021 \$2,062 million) and derivatives with a nominal value of \$24,088 million (2021 \$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 2022 was \$1,704 million (2021 \$1,407 million) in respect of liabilities of joint ventures and associates and \$680 million (2021 \$694 million) in respect of liabilities of other third parties. An amount of \$267 million (2021 \$337 million) is recorded as a liability at 31 December 2022 in relation to these guarantees. For all guarantees, maturity dates vary, and the 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.

29. 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 2022, the group had in place credit enhancements designed to mitigate approximately \$12.6 billion (2021 \$9.5 billion) of credit risk of which approximately \$10.3 billion (2021 \$7.5 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	2022	2021
AAA to AA-	9 %	14 %
A+ to A-	49 %	46 %
BBB+ to BBB-	15 %	14 %
BB+ to BB-	11 %	8 %
B+ to B-	12 %	16 %
CCC+ and below	4 %	2 %

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

29. 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					
	Gross amounts of recognized financial assets (liabilities)		Related amounts not set off in the balance sheet			
		Amounts set off	Net amounts presented on the balance sheet	Master netting arrangements	Cash collateral (received) pledged	Net amount
At 31 December 2022						
Derivative assets	33,199	(8,804)	24,395	(3,988)	(918)	19,489
Derivative liabilities	(34,918)	8,804	(26,114)	3,988	436	(21,690)
Trade and other receivables	17,947	(8,381)	9,566	(1,325)	(224)	8,017
Trade and other payables	(20,671)	8,381	(12,290)	1,325	61	(10,904)
At 31 December 2021						
Derivative assets	20,519	(7,769)	12,750	(3,104)	(414)	9,232
Derivative liabilities ^a	(21,683)	7,769	(13,914)	3,104	357	(10,453)
Trade and other receivables	17,105	(8,104)	9,001	(1,038)	(249)	7,714
Trade and other payables ^a	(19,279)	8,104	(11,175)	1,038	22	(10,115)

^a Comparative amounts for collateral pledged, and the resulting net exposure, have been updated to reflect current year 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. While there is the potential for concerns about the energy transition to impact banks' or debt investors' appetite to finance hydrocarbon activity, we do not anticipate any material change to the group's funding or liquidity in the short to medium term as a result of such concerns.

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 \$12,730 million (2021 \$12,575 million), allowing LCs to be issued for a maximum 24-month duration. There were also uncommitted secured LC facilities in place at 31 December 2022 for \$3,800 million (2021 \$4,290 million), which are secured against inventories or receivables when utilized. The facilities are held with over 28 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 2022, \$9,520 million (2021 \$9,154 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- (positive) and Moody's Investors Service rating is A2 (positive) and the Fitch Ratings' long-term credit rating is A (positive).

During 2022, a \$2 billion (2021 \$6 billion) long-term taxable bond was issued with a maturity term of 10 years. In addition the group drew down on perpetual hybrid capital instruments with a US dollar equivalent value of \$0.4 billion (2021 \$0.9 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 \$29.2 billion at 31 December 2022 (2021 \$30.7 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2022, the group had substantial amounts of undrawn borrowing facilities available, consisting of an undrawn committed \$8.0 billion (2021 \$8.0 billion) credit facility and \$4.0 billion (2021 \$4.0 billion) of standby facilities. As at 31 December 2022 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 2023 \$11.7 billion of 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 356.

The group manages liquidity risk associated with derivative contracts, other than derivative hedging instruments, based on the expected maturities of both derivative assets and liabilities as indicated in Note 30. Management does not currently anticipate any cash flows, other than noted below, that could be of a significantly different amount or could occur earlier than the expected maturity analysis provided.

29. 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.

	2022				2021			
	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	59,618	6,398	2,978	2,133	48,497	5,638	5,370	1,497
1 to 2 years	1,625	230	2,811	1,923	1,627	209	4,425	1,341
2 to 3 years	1,378	207	4,066	1,770	1,346	108	5,953	1,204
3 to 4 years	1,192	110	5,077	1,566	1,328	144	5,958	1,047
4 to 5 years	1,188	114	5,773	1,324	1,146	56	5,504	896
5 to 10 years	6,109	348	13,621	4,283	5,695	218	16,483	2,705
Over 10 years	772	224	13,135	2,828	1,699	233	14,744	1,699
	71,882	7,631	47,461	15,827	61,338	6,606	58,437	10,389

^a 2022 includes \$11,884 million (2021 \$13,170 million) in relation to the Gulf of Mexico oil spill, of which \$10,660 million (2021 \$11,883 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 \$23,970 million at 31 December 2022 (2021 \$27,048 million) to be received on the same day as the related cash outflows.

Cash outflows for derivative financial instruments at 31 December	\$ million	
	2022	2021
Within one year	1,492	1,497
1 to 2 years	2,531	1,492
2 to 3 years	2,053	2,531
3 to 4 years	5,575	2,053
4 to 5 years	3,584	5,575
5 to 10 years	7,627	8,618
Over 10 years	2,772	5,365
	25,634	27,131

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

30. Derivative financial instruments

In the normal course of business the group enters into derivative financial instruments (derivatives) to manage its normal business exposures in relation to commodity prices, foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt, consistent with risk management policies and objectives. An outline of the group's financial risks and the objectives and policies pursued in relation to those risks is set out in Note 29. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts.

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

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

Exchange traded derivatives are valued using closing prices provided by the exchange as at the balance sheet date. These derivatives are categorized within level 1 of the fair value hierarchy. Exchange traded derivatives are typically considered settled through the (normally daily) payment or receipt of variation margin.

Over-the-counter (OTC) financial swaps, 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.

30. Derivative financial instruments – continued

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

	2022		2021	
	Fair value asset	Fair value liability	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	634	(2,346)	272	(643)
Oil price derivatives	2,753	(1,961)	2,192	(1,567)
Natural gas price derivatives	15,437	(12,129)	6,823	(8,273)
Power price derivatives	5,527	(6,004)	3,105	(2,966)
Other derivatives	44	—	10	—
	24,395	(22,440)	12,402	(13,449)
Embedded derivatives				
Other embedded derivatives	—	(41)	—	(7)
	—	(41)	—	(7)
Cash flow hedges				
Currency forwards	—	—	1	—
	—	—	1	—
Fair value hedges				
Currency swaps	—	(3,670)	326	(465)
Interest rate swaps	—	(4)	21	—
	—	(3,674)	347	(465)
	24,395	(26,155)	12,750	(13,921)
Of which – current	11,554	(12,618)	5,744	(7,565)
– non-current	12,841	(13,537)	7,006	(6,356)

Derivatives held for trading

The group maintains active trading positions in a variety of derivatives. The contracts may be entered into for risk management purposes, to satisfy supply requirements or for entrepreneurial trading. Certain contracts are classified as held for trading, regardless of their original business objective, and are recognized at fair value with changes in fair value recognized in the income statement. Trading activities are undertaken by using a range of contract types in combination to create incremental gains by arbitraging prices between markets, locations and time periods. The net of these exposures is monitored using market value-at-risk techniques as described in Note 29.

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

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

	2022						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	536	14	10	10	9	55	634
Oil price derivatives	1,971	445	150	63	35	89	2,753
Natural gas price derivatives	7,157	3,740	749	442	316	3,033	15,437
Power price derivatives	1,848	1,317	623	376	291	1,072	5,527
Other derivatives	42	—	—	—	—	2	44
	11,554	5,516	1,532	891	651	4,251	24,395

	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

30. Derivative financial instruments – continued

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

	\$ million						
	2022						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(587)	(95)	(3)	(629)	(319)	(713)	(2,346)
Oil price derivatives	(1,615)	(318)	(23)	(4)	(1)	—	(1,961)
Natural gas price derivatives	(7,255)	(1,157)	(539)	(328)	(214)	(2,636)	(12,129)
Power price derivatives	(2,924)	(1,002)	(506)	(335)	(273)	(964)	(6,004)
	(12,381)	(2,572)	(1,071)	(1,296)	(807)	(4,313)	(22,440)

	\$ 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)

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						
	2022						
	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	207	17	19	4	—	—	247
Level 2	17,161	5,628	935	289	77	65	24,155
Level 3	1,525	1,014	783	659	601	4,215	8,797
	18,893	6,659	1,737	952	678	4,280	33,199
Less: netting by counterparty	(7,339)	(1,143)	(205)	(61)	(27)	(29)	(8,804)
	11,554	5,516	1,532	891	651	4,251	24,395
Fair value of derivative liabilities							
Level 1	(281)	(20)	(22)	(7)	—	—	(330)
Level 2	(18,116)	(2,901)	(702)	(915)	(437)	(805)	(23,876)
Level 3	(1,323)	(794)	(552)	(435)	(397)	(3,537)	(7,038)
	(19,720)	(3,715)	(1,276)	(1,357)	(834)	(4,342)	(31,244)
Less: netting by counterparty	7,339	1,143	205	61	27	29	8,804
	(12,381)	(2,572)	(1,071)	(1,296)	(807)	(4,313)	(22,440)
Net fair value	(827)	2,944	461	(405)	(156)	(62)	1,955

	\$ 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)

30. Derivative financial instruments – continued

Level 3 derivatives

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

	\$ million					
	Oil price	Natural gas price	Power price	Currency	Other	Total
Fair value contracts at 1 January 2022	199	534	40	(154)	10	629
Gains (losses) recognized in the income statement	17	508	334	215	34	1,108
Purchases ^a	–	(4)	(889)	–	–	(893)
Settlements	(73)	(210)	(32)	–	–	(315)
Transfers out of level 3	(115)	77	23	–	–	(15)
Net fair value of contracts at 31 December 2022	28	905	(524)	61	44	514
Deferred day-one gains (losses)						1,245
Derivative asset (liability)						1,759

	\$ 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

^a Primarily relates to the acquisition of EDF Energy Services.

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2022 was a \$1,223 million gain (2021 \$755 million gain related to derivatives still held at 31 December 2021).

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 \$7,829 million (2021 \$4,466 million net gain). 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.

As outlined in Note 1- Significant estimate and judgement: derivative financial instruments, LNG contracts are only recognised in the financial statements when associated cargoes are lifted. The embedded value in these contracts is not recognised and is subject to underlying commodity price volatility, as observed during 2021 and 2022. bp expects material profits may be realised in the future as LNG cargoes are delivered. bp generally price risk manages the exposure to LNG cargoes due for delivery in the near term where there is a liquid market. It does so on a portfolio basis using derivative instruments amongst other price risk management strategies. Under IFRS, these derivative instruments, which are subject to similar price volatility, are recorded at fair value through profit and loss at each reporting period, which creates an accounting mismatch in the financial statements between the accounting for LNG contracts and the derivatives used for risk management. For the year ended 31 December 2021, LNG prices rose significantly and material losses on LNG related derivative positions were recorded. For the year ended 31 December 2022 due to active risk management and the movement in the underlying commodity prices, there were no material gains or losses recorded on the associated derivative positions. For additional information, details of management's internal measure of performance are given in the Group Performance Report on page 32 and on page 354.

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 \$1,280 million (2021 \$775 million net loss and 2020 \$829 million net gain). Where the derivative is economically hedging finance debt, gains and losses on such derivative contracts are included within finance costs. 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 2022, the group held currency forwards designated as hedging instruments in cash flow hedge relationships of highly probable forecast non-US dollar capital expenditure. Note 29 outlines the group's approach to foreign currency exchange risk management. When the highly probable forecast capital expenditure designated as a hedged item occurs, a non-financial asset is recognized and is presented within the fixed asset section of the balance sheet.

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

30. Derivative financial instruments – continued

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

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

- counterparty's credit risk, the group mitigates counterparty credit risk by entering into derivative transactions with high credit quality counterparties; and
- differences in settlement timing between the derivative and hedged items. The latter impacts the discount factor used in the calculation of the hedge ineffectiveness. The group mitigates differences in timing between the derivatives and hedged items by applying a rolling strategy and by hedging currency pairs from stable economies. 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 2022				
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure		—	—	—
Commodity price risk				
Highly probable forecast sales		(825)	825	—
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	—

30. Derivative financial instruments – continued

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

	Carrying amount of hedging instrument		Nominal amounts of hedging instruments	
	Assets	Liabilities	\$ million	mmBtu
	\$ million	\$ million	\$ million	mmBtu
At 31 December 2022				
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	–	–	5	
Commodity price risk				
Highly probable forecast sales	–	–		(469)
At 31 December 2021				
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	1	–	55	
Commodity price risk				
Highly probable forecast sales	–	–		(420)

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

All of the nominal amount of hedging instruments at 31 December 2022 and 2021 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 2022 relating to highly probably forecast sales 349 mmBtu (2021 245 mmBtu) matures within 12 months and 120 mmBtu (2021 175 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			
	2022		2021	
	Forecast capital expenditure	Forecast sales	Forecast capital expenditure	Forecast sales
At 31 December				
Sterling/US dollar	1.25		1.33	
Henry Hub \$/mmBtu		4.03		3.24

Fair value hedges

At 31 December 2022, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk and foreign currency risk arising from group fixed rate debt issuances. Note 29 outlines the group's approach to interest rate and foreign currency exchange risk management. The interest rate swaps are used to convert US dollar denominated fixed rate borrowings into floating rate debt. The cross-currency interest rate swaps are used to convert sterling, euro, Swiss franc, Canadian dollar and Norwegian krone denominated fixed rate borrowings into US dollar floating rate debt. The group manages all risks derived from debt issuance, such as credit risk, however, the group applies hedge accounting only to certain components of interest rate and foreign currency risk in order to minimize hedge ineffectiveness. The interest rate and foreign currency exposures are identified and hedged on an instrument-by-instrument basis. For interest rate exposures, the group designates as a fair value hedge the benchmark interest rate component only. This is an observable and reliably measurable component of interest rate risk.

All of the fair value hedge accounting relationships currently in place are directly affected by 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 2022 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.

30. Derivative financial instruments – continued

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

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

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

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

\$ million			
	Change in fair value of hedging instrument used to calculate ineffectiveness	Change in fair value of hedged item used to calculate ineffectiveness	Hedge ineffectiveness recognized in profit or (loss)
At 31 December 2022			
Fair value hedges			
Interest rate risk on finance debt	26	(27)	1
Interest rate and foreign currency risk on finance debt	3,519	(3,495)	(24)
At 31 December 2021			
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)

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

\$ million			
	Carrying amount of hedging instrument		Nominal amounts of hedging instruments
	Assets	Liabilities	
At 31 December 2022			
Fair value hedges			
Interest rate risk on finance debt	–	(4)	368
Interest rate and foreign currency risk on finance debt	–	(3,670)	17,032
At 31 December 2021			
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

All hedging instruments are presented within derivative financial instruments on the group balance sheet. Ineffectiveness arising on fair value hedges is included within finance costs in the income statement.

30. Derivative financial instruments – continued

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 2022	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	–	216	–	152	–	–	–	368
Interest rate and foreign currency risk on finance debt	1,307	2,238	1,971	2,244	1,845	4,869	2,558	17,032
At 31 December 2021								
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

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	2022		2021	
	Interest rate swaps	Cross-currency interest rate swaps	Interest rate swaps	Cross-currency interest rate swaps
Interest rate	2.48 %	6.23 %	0.31 %	1.91 %
Sterling/US dollar		1.36		1.36
Euro/US dollar		1.13		1.13
Canadian dollar/US dollar		0.78		0.78

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 2022	Assets	Liabilities	Assets	Liabilities	Discontinued hedges
Fair value hedges					
Interest rate risk on finance debt	–	(422)	4	–	(337)
Interest rate and foreign currency risk on finance debt	–	(17,003)	2,312	–	–
At 31 December 2021					
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)	–

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

30. Derivative financial instruments – continued

Movement in reserves related to hedge accounting

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

	\$ million				
	Cash flow hedge reserve			Costs of hedging reserve	
	Highly probable forecast capital expenditure	Highly probable forecast sales	Purchase of equity ^a	Interest rate and foreign currency risk on finance debt	Total
At 1 January 2022	3	(134)	(651)	(190)	(972)
Recognized in other comprehensive income					
Cash flow hedges marked to market	(4)	(825)	–	–	(829)
Cash flow hedges reclassified to the income statement - hedged item affected profit or loss	–	851	651	–	1,502
Costs of hedging marked to market	–	–	–	61	61
Costs of hedging reclassified to the income statement	–	–	–	25	25
	(4)	26	651	86	759
Cash flow hedges transferred to the balance sheet	1	–	–	–	1
At 31 December 2022	–	(108)	–	(104)	(212)

	\$ 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)

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

All of the cash flow hedge reserve related to the purchase of equity was reclassified to the income statement during the year following bp's decision to exit its shareholding in Rosneft. The amount reclassified is presented in net impairment and losses on sale of businesses and fixed assets in the income statement. The remaining cash flow hedge reserve balances and amounts reclassified from the cash flow hedge reserve into profit or loss during the year relate to continuing hedge relationships. Amounts deferred in these cash flow hedge reserves that have been reclassified to profit or loss are presented in sales and other operating revenues in the income statement.

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

31. Called-up share capital

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

	2022		2021		2020	
	Shares thousand	\$ million	Shares thousand	\$ million	Shares thousand	\$ million
Issued						
8% cumulative first preference shares of £1 each ^a	7,233	12	7,233	12	7,233	12
9% cumulative second preference shares of £1 each ^a	5,473	9	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	20,778,082	5,194	21,449,782	5,362	21,535,840	5,383
Issue of new shares for employee share-based payment plans	55,000	14	35,001	9	34,000	9
Issue of new shares – other	165,105	41	–	–	–	–
Repurchase of ordinary share capital	(1,900,404)	(475)	(706,701)	(177)	(120,058)	(30)
At 31 December	19,097,783	4,774	20,778,082	5,194	21,449,782	5,362
		4,795		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 2022 the company repurchased 1,900 million ordinary shares for a total consideration of \$9,996 million, including transaction costs of \$54 million. All shares purchased were for cancellation. The repurchased shares represented 10.0% of ordinary share capital. A further 107 million ordinary shares were repurchased between the end of the reporting period and 17 February 2023, the latest practicable date before the completion of these financial statements, for a total cost of \$653 million of which \$497 million has been accrued at 31 December 2022. The number of shares in issue is reduced when shares are repurchased.

165 million new ordinary shares were issued in April 2022 as non-cash consideration for the acquisition of the public units of BP Midstream Partners LP.

Treasury shares^a

	2022		2021		2020	
	Shares thousand	Nominal value \$ million	Shares thousand	Nominal value \$ million	Shares thousand	Nominal value \$ million
At 1 January	1,137,457	283	1,187,650	296	1,296,856	323
Purchases for settlement of employee share plans	14,150	4	1,432	–	–	–
Issue of new shares for employee share-based payment plans	55,000	14	35,096	9	34,116	9
Shares re-issued for employee share-based payment plans	(81,680)	(20)	(86,721)	(22)	(143,322)	(36)
At 31 December	1,124,927	281	1,137,457	283	1,187,650	296
Of which – shares held in treasury by bp	940,571	235	1,037,201	259	1,105,157	275
– shares held in ESOP trusts	184,356	46	100,256	24	82,491	21
– shares held by bp's US share plan administrator ^b	–	–	–	–	2	–

^a See Note 32 for definition of treasury shares.

^b Held in the form of ADSs to meet the requirements of employee share-based payment plans in the US.

For each year presented, the balance of shares held in treasury by bp at 1 January represents 5.0% (2021 5.2% and 2020 5.4%) of the called-up ordinary share capital of the company.

During 2022, the movement in shares held in treasury by bp represented less than 0.5% (2021 less than 0.3% and 2020 less than 0.3%) of the ordinary share capital of the company.

32. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2022	5,215	12,745	1,705	27,206	46,871
Profit (loss) for the year	—	—	—	—	—
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications) ^a	—	—	—	—	—
Cash flow hedges and costs of hedging (including reclassifications)	—	—	—	—	—
Share of items relating to equity-accounted entities, net of tax	—	—	—	—	—
Other	—	—	—	—	—
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	—	—	—	—
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	—	—	—	—	—
Issue of ordinary share capital	41	779	—	—	820
Repurchases of ordinary share capital	(475)	—	475	—	—
Share-based payments, net of tax ^b	14	168	—	—	182
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	—	—	—	—	—
At 31 December 2022	4,795	13,692	2,180	27,206	47,873
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	—	—	—	—	—
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 ^c	—	—	—	—	—
At 31 December 2021	5,215	12,745	1,705	27,206	46,871

^a Following, bp's decision to exit its shareholding in Rosneft on 27 February 2022 \$10,372 million was reclassified to the income statement. See Note 1 - Investment in Rosneft.

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

^c 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.

32. 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	
(12,624)	(9,572)	(851)	(176)	(1,027)	51,815	75,463	13,041	1,935	90,439
—	—	—	—	—	(2,487)	(2,487)	519	611	(1,357)
—	6,914	—	—	—	—	6,914	—	(61)	6,853
—	—	671	103	774	—	774	—	—	774
—	—	—	—	—	402	402	—	—	402
—	—	—	—	—	(225)	(225)	—	—	(225)
—	—	—	—	—	408	408	—	—	408
—	—	(4)	—	(4)	—	(4)	—	—	(4)
—	6,914	667	103	770	(1,902)	5,782	519	550	6,851
—	—	—	—	—	(4,365)	(4,365)	—	(294)	(4,659)
—	—	1	—	1	—	1	—	—	1
—	—	—	—	—	—	820	—	—	820
—	—	—	—	—	(10,493)	(10,493)	—	—	(10,493)
471	—	—	—	—	194	847	—	—	847
—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	(4)	(4)	374	—	370
—	15	—	—	—	—	15	(544)	—	(529)
—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	(513)	(513)	—	(144)	(657)
(12,153)	(2,643)	(183)	(73)	(256)	34,732	67,553	13,390	2,047	82,990
(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

32. Capital and reserves – continued

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2020	5,404	12,417	1,498	27,206	46,525
Profit (loss) for the year	—	—	—	—	—
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications)	—	—	—	—	—
Cash flow hedges and costs of hedging (including reclassifications)	—	—	—	—	—
Share of items relating to equity-accounted entities, net of tax ^a	—	—	—	—	—
Other	—	—	—	—	—
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	—	—	—	—
Cash flow hedges that will subsequently be transferred to the balance sheet	—	—	—	—	—
Total comprehensive income					
Dividends	—	—	—	—	—
Cash flow hedges transferred to the balance sheet, net of tax	—	—	—	—	—
Repurchases of ordinary share capital	(30)	—	30	—	—
Share-based payments, net of tax ^b	9	167	—	—	176
Share of equity-accounted entities' changes in equity, net of tax ^c	—	—	—	—	—
Issue of perpetual hybrid bonds	—	—	—	—	—
Payments on perpetual hybrid bonds	—	—	—	—	—
Tax on issue of perpetual hybrid bonds	—	—	—	—	—
Transactions involving non-controlling interests, net of tax ^d	—	—	—	—	—
At 31 December 2020	5,383	12,584	1,528	27,206	46,701

^a Principally foreign exchange effects relating to the Russian rouble.

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

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

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

32. 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	
(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

32. Capital and reserves – continued

Share capital

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

Share premium account

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

Capital redemption reserve

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

Merger reserve

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

Treasury shares

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

Foreign currency translation reserve

The foreign currency translation reserve records exchange differences arising from the translation of the financial statements of foreign operations. Upon disposal of foreign operations, the related accumulated exchange differences are reclassified to the income statement. Following, bp's decision to exit its shareholding in Rosneft on 27 February 2022 \$10,372 million was reclassified to the income statement. See Note 1 - Investment in Rosneft.

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. At 31 December 2021 and 2020 it included \$651 million relating to the acquisition of an 18.5% interest in Rosneft in 2013. Following bp's decision to exit its shareholding in Rosneft on 27 February 2022 the full amount was reclassified to the income statement. See Note 1 - Investment in Rosneft. 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 \$468 million (2021 \$499 million and 2020 \$89 million) and \$468 million (2021 \$497 million and 2020 \$89 million) respectively. The accumulated non-controlling interest at the end of the year was \$12,066 million (2021 \$12,081 million).

Non-controlling interests also includes perpetual subordinated hybrid securities issued during 2022 and 2021 by a group subsidiary, of \$1,324 million. The proceeds from these issuances 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 principal 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. Payments made to and profit attributed to these hybrid security holders in the year totalled \$61 million (2021 \$nil) and \$51 million (2021 \$10 million) respectively. The accumulated non-controlling interest at the end of the year was \$1,324 million (2021 \$960 million).

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.

32. Capital and reserves – continued

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

	\$ million		
	2022		
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	6,973	(120)	6,853
Cash flow hedges (including reclassifications)	677	(6)	671
Costs of hedging (including reclassifications)	86	17	103
Share of items relating to equity-accounted entities, net of tax	402	–	402
Other	–	(225)	(225)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	340	68	408
Cash flow hedges that will subsequently be transferred to the balance sheet	(4)	–	(4)
Other comprehensive income	8,474	(266)	8,208
			\$ 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)

33. Contingent liabilities and legal proceedings

Contingent liabilities

There were contingent liabilities at 31 December 2022 in respect of guarantees and indemnities entered into as part of the ordinary course of the group's business. No material losses are likely to arise from such contingent liabilities. Further information on financial guarantees is included in Note 29.

In the normal course of the group's business, bp group entities are subject to legal and regulatory proceedings arising out of current and past operations, including matters related to commercial disputes, product liability, antitrust, commodities trading, premises-liability claims, consumer protection, general health, safety, climate change and environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. The amounts claimed could be significant and could be material to the group's results of operations, financial position or liquidity. While it is difficult to predict the ultimate outcome in some cases, bp expects that the impact of current legal and regulatory proceedings on the group's results of operations, liquidity or financial position will not be material.

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

33. Contingent liabilities and legal proceedings – continued

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

If 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 \$16 billion (2021 \$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. 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. (BXP) 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.

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 2022, there were 105 pending lawsuits brought by class members claiming LMPCs.

Other civil complaints – economic loss

All of the remaining economic loss and property damage claims from individuals and businesses have been settled or dismissed.

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 (including more than 300 cases in which the courts granted BXP's motions for summary judgment). As of 31 December 2022, 414 cases remained pending.

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 BXP, BPAPC, and other entities which they claim are 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. BXP 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. Following the district court's certification of the class of 25 September 2019, various challenges and appeals have been made by both bp and ACS in relation to that decision and the class notification procedures, including the validity of signatures and supporting papers of purported class members. Final decisions on outstanding motions in these matters are 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.

33. Contingent liabilities and legal proceedings – continued

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. In 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. bp complied with the Order under protest and appealed the FERC's decision to the US Court of Appeals. On 20 October 2022, the Fifth Circuit issued an opinion upholding the FERC's finding that bp had engaged in market manipulation. The Fifth Circuit also found that the FERC did not have jurisdiction over most of the transactions identified as being violations. The matter has been remanded back to the FERC for further proceedings and reassessment of the penalty.

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 and in future reports will not report on lead paint litigation absent any material developments.

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.

Defendants removed all of these lawsuits to federal court and the removals were contested by plaintiffs, eventually resulting in a decision from the US Fifth Circuit Court of Appeals rejecting defendants' "federal officer" jurisdiction removal grounds in one of the two lead cases – *Plaquemines Parish v. Riverwood, et al.* Defendants' petition for writ of certiorari to the US Supreme Court seeking review of the US Fifth Circuit's *Riverwood* decision was denied in early 2023. On remand from the US District Court, the state court in the other lead case of *Cameron Parish v. Auster et al.* has preliminarily established a November, 2023 trial date. bp is the lead defendant in *Auster* but is not named in the *Riverwood* case.

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

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

34. Remuneration of senior management and non-executive directors

Remuneration of directors

	\$ million		
	2022	2021	2020
Total for all directors			
Emoluments	8	9	6
Amounts received under incentive schemes ^a	13	4	14
Total	21	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

Full details of individual directors' remuneration are given in the Directors' remuneration report on page 112.

Remuneration of directors and senior management

	\$ million		
	2022	2021	2020
Total for all senior management and non-executive directors			
Short-term employee benefits	31	30	17
Pensions and other post-retirement benefits	—	1	2
Share-based payments	31	32	52
Termination benefits	—	—	8
Total	62	63	79

Senior management comprises members of the leadership team, see pages 84-85 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.

Related party transactions

Transactions between the group and its significant joint ventures and associates are summarized in Financial statements – Note 16 and Note 17. In the ordinary course of its business, the group enters into transactions with various organizations with which some of its directors or executive officers are associated. Except as described in this report, the group did not have any material transactions or transactions of an unusual nature with, and did not make loans to, related parties in the period commencing 1 January 2022 to 17 February 2023.

35. Employee costs and numbers

Employee costs	\$ million		
	2022	2021	2020
Wages and salaries ^a	7,486	6,934	7,600
Social security costs	720	733	729
Share-based payments ^b	1,034	733	728
Pension and other post-retirement benefit costs	576	457	852
	9,816	8,857	9,909

Average number of employees ^{c,d}	2022			2021			2020		
	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
gas & low carbon energy	700	3,400	4,100	400	3,400	3,800			
oil production & operations	3,000	5,700	8,700	3,100	6,000	9,100			
customers & products ^e	8,000	35,700	43,700	6,200	35,800	42,000			
other businesses and corporate	1,300	8,500	9,800	1,400	7,700	9,100			
	13,000	53,300	66,300	11,100	52,900	64,000	12,400	55,700	68,100

^a Includes termination costs of \$27 million (2021 \$74 million and 2020 \$1,237 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 Comparative data for the new reportable segments from 2021 onwards is not available for 2020.

^e Includes 23,300 (2021 21,300 and 2020 19,100) service station staff.

36. Auditor's remuneration

Fees	\$ million		
	2022	2021	2020
The audit of the company annual accounts ^a	36	37	30
The audit of accounts of subsidiaries of the company	15	15	11
Total audit	51	52	41
Audit-related assurance services ^b	4	5	11
Total audit and audit-related assurance services	55	57	52
Non-audit and other assurance services	—	—	1
Services relating to bp pension plans	1	1	1
	56	58	54

^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.

2022 includes \$0.3 million of additional fees for 2021. 2021 includes \$1.0 million of additional fees for 2020. 2020 includes \$0.5 million of additional fees for 2019. 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 2022 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 \$56 million (2021 \$58 million and 2020 \$54 million) is required to be presented as follows: audit \$51 million (2021 \$52 million and 2020 \$41 million); other audit-related \$4 million (2021 \$5 million and 2020 \$11 million); tax \$nil (2021 \$nil and 2020 \$nil); and all other fees \$1 million (2021 \$1 million and 2020 \$2 million).

37. Subsidiaries, joint arrangements and associates^a

The more important subsidiaries, joint arrangements and associates of the group at 31 December 2022 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 13 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	Investment holding
Azerbaijan			
BP Exploration (Caspian Sea) Limited	100	England & Wales	Exploration and production
BP Exploration (Azerbaijan) Limited	100	England & Wales	Exploration and production
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	
Archaea Energy Inc.	100	US	
BP Capital Markets America Inc.	100	US	Bioenergy
			Finance
Joint arrangements			
Angola			
Azule Energy Holdings Limited	50	England & Wales	Exploration and production
Argentina			
Pan American Energy Group S.L.	50	Spain	Integrated oil operations

^a There were no important associates in the group at 31 December 2022.

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 361-366.

^a See Note 1 - Investment in Rosneft.

Oil and natural gas exploration and production activities

	\$ million									
	2022									
	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	30,010	—	65,126	6	16,720	20,257	—	39,899	6,324	178,342
Unproved properties	397	—	2,976	1,875	2,507	2,535	—	1,622	659	12,571
	30,407	—	68,102	1,881	19,227	22,792	—	41,521	6,983	190,913
Accumulated depreciation	21,757	—	37,461	1,586	13,849	18,207	—	21,642	4,588	119,090
Net capitalized costs	8,650	—	30,641	295	5,378	4,585	—	19,879	2,395	71,823
Costs incurred for the year ended 31 December^{a b}										
Acquisition of properties										
Proved	12	—	183	—	—	—	—	245	—	440
Unproved	—	—	37	164	2	14	—	—	—	217
	12	—	220	164	2	14	—	245	—	657
Exploration and appraisal costs ^c	39	—	288	137	235	103	—	73	17	892
Development	318	—	3,825	15	483	1,378	—	1,555	176	7,750
Total costs	369	—	4,333	316	720	1,495	—	1,873	193	9,299
Results of operations for the year ended 31 December^a										
Sales and other operating revenues ^d										
Third parties	549	—	2,101	420	2,977	3,836	—	6,551	1,588	18,022
Sales between businesses	5,747	—	12,746	—	538	2,146	—	9,932	1,472	32,581
	6,296	—	14,847	420	3,515	5,982	—	16,483	3,060	50,603
Exploration expenditure	11	—	144	109	172	57	—	94	(2)	585
Production costs	498	—	2,102	83	327	592	—	723	107	4,432
Production taxes	1	—	194	—	513	—	—	1,544	73	2,325
Other costs (income) ^e	(210)	(47)	2,926	63	96	206	32	(44)	300	3,322
Depreciation, depletion and amortization	1,242	—	3,122	18	680	2,075	1	2,495	384	10,017
Net impairments and (gains) losses on sale of businesses and fixed assets ^f	(433)	(901)	217	(3)	1,570	(1,189)	1,523	(341)	(43)	400
	1,109	(948)	8,705	270	3,358	1,741	1,556	4,471	819	21,081
Profit (loss) before taxation ^g	5,187	948	6,142	150	157	4,241	(1,556)	12,012	2,241	29,522
Allocable taxes	4,443	—	1,409	50	1,814	886	(5)	6,651	842	16,090
Results of operations	744	948	4,733	100	(1,657)	3,355	(1,551)	5,361	1,399	13,432

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

^b Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

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

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

^e Includes property taxes and other government take. The UK region includes a \$256-million gain which is offset by corresponding charges primarily in the US region, relating to the group self-insurance programme.

^f Russia impairments include other businesses with Rosneft, which were reported in the oil production and operation segment. The Rosneft impairment is reported in the other businesses and corporate segment. See Note 1 - Investment in Rosneft and Note 17 Investments in Associates.

^g Excludes the unwinding of the discount on provisions and payables amounting to \$294 million which is included in finance costs in the group income statement.

Oil and natural gas exploration and production activities – continued

								\$ million		
								2022		
	Europe		North America		South America	Africa	Asia	Australasia	Total	
	UK	Rest of Europe	US	Rest of North America			Russia ^a	Rest of Asia		
Equity-accounted entities (bp share)										
Capitalized costs at 31 December^{b c}										
Gross capitalized costs										
Proved properties	–	3,739	–	–	12,000	7,927	–	8,381	–	32,047
Unproved properties	–	611	–	–	120	371	–	–	–	1,102
	–	4,350	–	–	12,120	8,298	–	8,381	–	33,149
Accumulated depreciation	–	1,800	–	–	6,356	572	–	553	–	9,281
Net capitalized costs	–	2,550	–	–	5,764	7,726	–	7,828	–	23,868
Costs incurred for the year ended 31 December^{b d e}										
Acquisition of properties ^c										
Proved	–	1,224	–	–	–	–	–	–	–	1,224
Unproved	–	204	–	–	–	–	–	–	–	204
	–	1,428	–	–	–	–	–	–	–	1,428
Exploration and appraisal costs ^d	–	46	–	–	22	60	28	–	–	156
Development ^f	–	(24)	–	–	673	292	428	625	–	1,994
Total costs	–	1,450	–	–	695	352	456	625	–	3,578
Results of operations for the year ended 31 December^b										
Sales and other operating revenues ^g										
Third parties	–	2,050	–	–	2,171	1,137	–	829	–	6,187
Sales between businesses	–	–	–	–	–	–	6,052	–	–	6,052
	–	2,050	–	–	2,171	1,137	6,052	829	–	12,239
Exploration expenditure	–	39	–	–	–	7	13	–	–	59
Production costs	–	148	–	–	628	246	411	191	–	1,624
Production taxes	–	–	–	–	397	15	4,435	–	–	4,847
Other costs (income)	–	(6)	–	–	16	152	97	20	–	279
Depreciation, depletion and amortization	–	348	–	–	462	572	535	553	–	2,470
Net impairments and losses on sale of businesses and fixed assets	–	164	–	–	–	–	–	–	–	164
	–	693	–	–	1,503	992	5,491	764	–	9,443
Profit (loss) before taxation	–	1,357	–	–	668	145	561	65	–	2,796
Allocable taxes	–	1,098	–	–	77	81	109	66	–	1,431
Results of operations	–	259	–	–	591	64	452	(1)	–	1,365

^a Amounts reported for Russia in this table are bp's estimated share of the equity-accounted entities, including Rosneft's worldwide activities (of which insignificant amounts relate to outside Russia). See Note 1 - Investment in Rosneft and Note 17 - Investments in Associates.

^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 Rest of Europe development costs are negative due to a true-up of prior period spend.

^g Presented net of sales tax.

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	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.

^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.

Movements in estimated net proved reserves

million barrels										
2022										
Crude oil ^{a,b}	Europe		North America		South America	Africa ^c	Asia	Australasia		Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	9	—	(11)	—	(1)	1	—	(40)	(4)	(47)
Improved recovery	2	—	(2)	—	—	4	—	—	—	5
Purchases of reserves-in-place	—	—	—	—	—	—	—	3	—	3
Discoveries and extensions	—	—	22	—	—	1	—	—	—	23
Production	(29)	—	(108)	(5)	(2)	(31)	—	(112)	(5)	(292)
Sales of reserves-in-place	—	—	(1)	(185)	—	(80)	—	(157)	(3)	(426)
	(18)	—	(100)	(191)	(3)	(105)	—	(306)	(11)	(734)
At 31 December^c										
Developed	153	—	679	—	4	24	—	717	20	1,596
Undeveloped	109	—	527	—	5	2	—	356	1	1,000
	261	—	1,206	—	9	26	—	1,073	21	2,596
Equity-accounted entities (bp share)^d										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	(17)	—	1	(1)	23	4	(46)	—	(37)
Improved recovery	—	1	—	—	14	25	—	—	—	40
Purchases of reserves-in-place	—	42	—	—	—	165	—	152	—	359
Discoveries and extensions	—	2	—	—	—	—	—	—	—	2
Production	—	(17)	—	(1)	(21)	(12)	(55)	(9)	—	(115)
Sales of reserves-in-place ^e	—	(25)	—	(10)	—	(3)	(5,535)	(1)	—	(5,574)
	—	(15)	—	(10)	(8)	198	(5,585)	95	—	(5,325)
At 31 December										
Developed	—	90	—	5	276	127	—	95	—	592
Undeveloped	—	16	—	7	244	74	—	1	—	342
	—	106	—	12	520	201	—	96	—	935
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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
At 31 December										
Developed	153	90	679	5	279	151	—	812	20	2,188
Undeveloped	109	16	527	7	249	76	—	358	1	1,343
	261	106	1,206	12	529	227	—	1,169	21	3,531

^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 3 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 assets held for sale in Algeria

^f bp's decision to exit its Russia business, including its shareholding in Rosneft, is treated as sales of reserves in place.

Movements in estimated net proved reserves – continued

million barrels										
2022										
Natural gas liquids ^{a,b}										
Europe		North America		South America	Africa ^f	Asia		Australasia	Total	
UK	Rest of Europe	US ^c	Rest of North America			Russia	Rest of Asia			
Subsidiaries										
At 1 January										
Developed	8	–	132	–	2	9	–	–	2	153
Undeveloped	–	–	195	–	19	1	–	–	–	215
	9	–	328	–	21	10	–	–	2	368
Changes attributable to										
Revisions of previous estimates	(1)	–	101	–	(18)	(1)	–	–	–	81
Improved recovery	–	–	16	–	–	1	–	–	–	17
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	1	–	–	1	–	–	–	2
Production ^c	(2)	–	(28)	–	(2)	(2)	–	–	(1)	(34)
Sales of reserves-in-place	–	–	(1)	–	–	(1)	–	–	–	(1)
	(2)	–	90	–	(19)	(2)	–	–	(1)	64
At 31 December^d										
Developed	6	–	181	–	1	6	–	–	1	196
Undeveloped	–	–	236	–	–	1	–	–	–	237
	6	–	417	–	1	7	–	–	1	432
Equity-accounted entities (bp share)^e										
At 1 January										
Developed	–	6	–	–	2	17	100	–	–	125
Undeveloped	–	–	–	–	–	–	41	–	–	41
	–	6	–	–	2	17	140	–	–	166
Changes attributable to										
Revisions of previous estimates	–	(1)	–	–	2	7	–	–	–	8
Improved recovery	–	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	2	–	–	–	20	–	–	–	21
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production	–	(1)	–	–	–	(1)	–	–	–	(2)
Sales of reserves-in-place ^g	–	(2)	–	–	–	(17)	(140)	–	–	(159)
	–	(2)	–	–	2	9	(140)	–	–	(132)
At 31 December										
Developed	–	4	–	–	3	17	–	–	–	23
Undeveloped	–	–	–	–	1	9	–	–	–	10
	–	4	–	–	4	26	–	–	–	34
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	8	6	132	–	4	26	100	–	2	278
Undeveloped	–	–	195	–	19	1	41	–	–	256
	9	6	328	–	22	27	140	–	2	534
At 31 December										
Developed	6	4	181	–	4	23	–	–	1	219
Undeveloped	–	–	236	–	1	10	–	–	–	247
	6	4	417	–	5	33	–	–	1	466

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

^d Includes 0.4 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 assets held for sale in Algeria

^g bp's decision to exit its Russia business, including its shareholding in Rosneft, is treated as sales of reserves in place.

Movements in estimated net proved reserves – continued

	million barrels									
	2022									
	Europe		North America		South America	Africa ^f	Asia		Australasia	Total
	UK	Rest of Europe	US ^c	Rest of North America			Russia	Rest of Asia		
Total liquids^{a, b}										
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	8	—	89	—	(19)	—	—	(40)	(4)	34
Improved recovery	2	—	14	—	—	5	—	—	—	22
Purchases of reserves-in-place	1	—	—	—	—	—	—	3	—	3
Discoveries and extensions	—	—	23	—	—	1	—	—	—	25
Production ^c	(31)	—	(136)	(5)	(3)	(34)	—	(112)	(5)	(326)
Sales of reserves-in-place	—	—	(2)	(185)	—	(80)	—	(157)	(4)	(428)
	(20)	—	(11)	(191)	(22)	(107)	—	(306)	(13)	(670)
At 31 December^d										
Developed	159	—	860	—	5	30	—	717	20	1,791
Undeveloped	109	—	763	—	5	3	—	356	1	1,237
	267	—	1,623	—	11	33	—	1,073	22	3,029
Equity-accounted entities (bp share)^e										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	(18)	—	1	1	30	4	(46)	—	(29)
Improved recovery	—	1	—	—	14	25	—	—	—	40
Purchases of reserves-in-place	—	44	—	—	—	185	—	152	—	380
Discoveries and extensions	—	2	—	—	—	—	—	—	—	2
Production	—	(18)	—	(1)	(21)	(13)	(55)	(9)	—	(117)
Sales of reserves-in-place ^g	—	(27)	—	(10)	—	(19)	(5,675)	(1)	—	(5,733)
	—	(17)	—	(10)	(6)	207	(5,726)	95	—	(5,457)
At 31 December										
Developed	—	94	—	5	278	144	—	95	—	616
Undeveloped	—	16	—	7	245	83	—	1	—	352
	—	110	—	12	523	227	—	96	—	968
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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
At 31 December										
Developed	159	94	860	5	283	174	—	812	20	2,407
Undeveloped	109	16	763	7	250	86	—	358	1	1,590
	267	110	1,623	12	534	260	—	1,169	22	3,997

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

^d Also includes 3 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 assets held for sale in Algeria.

^g bp's decision to exit its Russia business, including its shareholding in Rosneft, is treated as sales of reserves in place.

Movements in estimated net proved reserves – continued

										billion cubic feet
										2022
Natural gas ^{a, b}		Europe	North America	South America	Africa ^f	Asia	Australasia	Total		
	UK	Rest of Europe	US	Rest of North America		Russia	Rest of Asia			
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	6	–	449	–	2	180	–	(575)	(165)	(102)
Improved recovery	1	–	46	–	–	–	–	–	–	47
Purchases of reserves-in-place	2	–	–	–	–	–	–	92	–	94
Discoveries and extensions	–	–	10	–	–	87	–	21	10	128
Production ^c	(109)	–	(493)	–	(476)	(517)	–	(561)	(276)	(2,432)
Sales of reserves-in-place	–	–	(9)	–	–	(93)	–	(47)	–	(149)
	(100)	–	4	–	(474)	(344)	–	(1,069)	(431)	(2,414)
At 31 December^d										
Developed	360	–	2,655	–	1,077	1,021	–	2,594	1,684	9,392
Undeveloped	41	–	3,154	–	748	221	–	2,125	407	6,696
	401	–	5,809	–	1,825	1,242	–	4,719	2,091	16,087
Equity-accounted entities (bp share)^e										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	–	(7)	–	1	162	131	53	–	–	340
Improved recovery	–	–	–	–	82	–	–	–	–	82
Purchases of reserves-in-place	–	14	–	–	–	575	–	45	–	634
Discoveries and extensions	–	4	–	–	–	–	–	–	–	4
Production ^c	–	(25)	–	–	(128)	(36)	(86)	(2)	–	(277)
Sales of reserves-in-place ^g	–	(49)	–	(4)	–	(803)	(18,645)	–	–	(19,501)
	–	(64)	–	(3)	115	(133)	(18,678)	43	–	(18,719)
At 31 December										
Developed	–	72	–	3	974	534	–	43	–	1,627
Undeveloped	–	5	–	2	606	154	–	–	–	767
	–	77	–	5	1,580	689	–	43	–	2,394
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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
At 31 December										
Developed	360	72	2,655	3	2,051	1,556	–	2,637	1,684	11,018
Undeveloped	41	5	3,154	2	1,355	375	–	2,125	407	7,463
	401	77	5,809	5	3,405	1,931	–	4,762	2,091	18,481

^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 122 billion cubic feet of natural gas consumed in operations, 86 billion cubic feet in subsidiaries, 36 billion cubic feet in equity-accounted entities.

^d Includes 547 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 assets held for sale in Algeria.

^g bp's decision to exit our Russia business, including our shareholding in Rosneft, is treated as sales of reserves in place.

Movements in estimated net proved reserves – continued

Total hydrocarbons ^{a,b}	million barrels of oil equivalent ^c									
	2022									
	Europe		North America		South America	Africa ^h	Asia	Australasia		Total
UK	Rest of Europe	US ^f	Rest of North America			Russia	Rest of Asia			
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	9	—	167	—	(18)	31	—	(139)	(33)	17
Improved recovery	2	—	22	—	—	5	—	—	—	30
Purchases of reserves-in-place	1	—	—	—	—	—	—	18	—	19
Discoveries and extensions	—	—	25	—	—	16	—	4	2	47
Production ^{d,e}	(50)	—	(221)	(5)	(85)	(123)	—	(209)	(53)	(746)
Sales of reserves-in-place	—	—	(3)	(185)	—	(96)	—	(165)	(4)	(453)
	(37)	—	(10)	(191)	(103)	(167)	—	(491)	(87)	(1,086)
At 31 December^f										
Developed	221	—	1,318	—	191	206	—	1,164	311	3,411
Undeveloped	116	—	1,306	—	134	41	—	723	72	2,392
	337	—	2,624	—	325	247	—	1,887	382	5,802
Equity-accounted entities (bp share)^g										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	(19)	—	1	29	53	13	(46)	—	30
Improved recovery	—	1	—	—	28	25	—	—	—	54
Purchases of reserves-in-place	—	46	—	—	—	284	—	159	—	489
Discoveries and extensions	—	2	—	—	—	—	—	—	—	2
Production ^e	—	(22)	—	(1)	(43)	(19)	(70)	(10)	—	(165)
Sales of reserves-in-place ⁱ	—	(36)	—	(10)	—	(158)	(8,890)	(1)	—	(9,095)
	—	(28)	—	(11)	14	184	(8,946)	102	—	(8,685)
At 31 December										
Developed	—	106	—	6	446	236	—	102	—	896
Undeveloped	—	17	—	7	349	110	—	1	—	485
	—	123	—	13	796	346	—	103	—	1,381
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
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
At 31 December										
Developed	221	106	1,318	6	637	442	—	1,266	311	4,307
Undeveloped	116	17	1,306	7	484	151	—	724	72	2,877
	337	123	2,624	13	1,121	593	—	1,990	382	7,183

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

^e Includes 21 million barrels of oil equivalent of natural gas consumed in operations, 15 million barrels of oil equivalent in subsidiaries, 6 million barrels of oil equivalent in equity-accounted entities.

^f Includes 98 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 assets held for sale in Algeria.

ⁱ bp's decision to exit our Russia business, including our shareholding in Rosneft, is treated as sales of reserves in place.

Movements in estimated net proved reserves – continued

Crude oil ^{a,b}	million barrels									
	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	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

	million barrels									
Natural gas liquids ^{a,b}	2021									
	Europe		North America		South America	Africa	Asia	Australasia		Total
	UK	Rest of Europe	USc	Rest of North America			Russia	Rest of Asia		
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										
	2021										
Total 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			
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 mmbob 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
										2021
Natural gas^{a,b}										
		Europe		North America		South America	Africa	Asia	Australasia	Total
		UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia	
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 1 billion 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

Total hydrocarbons ^{a,b}	million barrels of oil equivalent ^c									
	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 98 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 129mmbbl 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, 1 million 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}	million barrels									
	2020									
	Europe		North America		South America	Africa	Asia		Australasia	Total
UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asiatic			
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 Asiatic			
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

	million barrels									
	2020									
Total liquids ^{a,b}	Europe		North America		South America	Africa	Asia	Australasia		Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asiatic		
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 mmbob 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 ^e		
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^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 mboe 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.

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									
	2022									
	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	34,900	—	154,500	—	16,400	9,400	—	151,500	23,600	390,300
Future production cost ^b	13,600	—	36,000	—	5,300	1,300	—	42,700	5,200	104,100
Future development cost ^b	1,100	—	12,200	—	1,400	700	—	8,800	1,900	26,100
Future taxation ^c	12,600	—	19,800	—	5,000	1,900	—	65,200	5,500	110,000
Future net cash flows	7,600	—	86,500	—	4,700	5,500	—	34,800	11,000	150,100
10% annual discount ^d	3,400	—	38,200	—	700	1,000	—	11,800	4,000	59,100
Standardized measure of discounted future net cash flows ^e	4,200	—	48,300	—	4,000	4,500	—	23,000	7,000	91,000
Equity-accounted entities (bp share)^f										
Future cash inflows ^a	—	12,800	—	—	49,800	20,500	—	9,200	—	92,300
Future production cost ^b	—	2,100	—	—	22,000	6,300	—	4,900	—	35,300
Future development cost ^b	—	400	—	—	4,900	2,800	—	3,000	—	11,100
Future taxation ^c	—	8,100	—	—	7,100	4,300	—	400	—	19,900
Future net cash flows	—	2,200	—	—	15,800	7,100	—	900	—	26,000
10% annual discount ^d	—	400	—	—	9,300	2,200	—	200	—	12,100
Standardized measure of discounted future net cash flows ^g	—	1,800	—	—	6,500	4,900	—	700	—	13,900
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows ^h	4,200	1,800	48,300	—	10,500	9,400	—	23,700	7,000	104,900

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	(22,800)	(4,600)	(27,400)
Development costs for the current year as estimated in previous year	5,500	1,800	7,300
Extensions, discoveries and improved recovery, less related costs	1,600	900	2,500
Net changes in prices and production cost	80,800	11,100	91,900
Revisions of previous reserves estimates	(18,300)	(2,700)	(21,000)
Net change in taxation	(23,000)	1,400	(21,600)
Future development costs	(2,100)	(800)	(2,900)
Net change in purchase and sales of reserves-in-place	(4,300)	(34,800)	(39,100)
Addition of 10% annual discount	6,700	3,800	10,500
Total change in the standardized measure during the yearⁱ	24,100	(23,900)	200

^a The marker prices used were Brent \$101.24/bbl, Henry Hub \$6.19/mmBtu.

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

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

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

^e Non-controlling interests in BP Trinidad and Tobago LLC amounted to \$1,216 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 No reserves are reported for Russia following bp's announcement that it will exit the country. The impact of this change is primarily included within sales of reserves-in-place. See Note 1 - Significant judgements and estimates: investment in Rosneft.

^h Includes future net cash flows for assets held for sale at 31 December 2022.

ⁱ Total change in the standardized measure during the year includes the effect of exchange rate movements.

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

	\$ 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.

^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'.

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 2022, 2021 and 2020.

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										
2022	80	—	296	15	5	83	—	307	12	797
2021	82	—	308	25	5	110	—	318	13	860
2020	96	—	345	22	7	123	—	375	15	983
Natural gas liquids thousand barrels per day										
2022	5	—	76	—	4	6	—	—	2	93
2021	5	—	70	—	4	7	—	—	2	88
2020	5	—	79	—	7	8	—	—	2	101
Natural gas ^f million cubic feet per day										
2022	271	—	1,291	—	1,276	1,353	—	1,485	752	6,428
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
Equity-accounted entities (bp share)										
Crude oil ^e thousand barrels per day										
2022	—	47	—	—	59	33	150	25	—	314
2021	—	48	—	—	55	1	887	—	—	991
2020	—	50	—	—	54	1	903	—	—	1,009
Natural gas liquids thousand barrels per day										
2022	—	2	—	—	1	5	—	—	—	9
2021	—	3	—	—	1	6	3	—	—	12
2020	—	3	—	—	1	7	3	—	—	14
Natural gas ^f million cubic feet per day										
2022	—	66	—	—	296	64	248	—	—	674
2021	—	66	—	—	284	77	1,423	—	—	1,849
2020	—	61	—	—	286	92	1,327	—	—	1,765

^a Production excludes royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

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

^c Amounts reported for Russia include bp's share of Rosneft worldwide activities, including insignificant amounts outside Russia.

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

^e Crude oil includes condensate.

^f Natural gas production excludes gas consumed in operations.

Operational and statistical information – continued

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the group and its equity-accounted entities had interests as at 31 December 2022. A 'gross' well or acre is one in which a whole or fractional working interest is owned, while the number of 'net' wells or acres is the sum of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves.

		Europe		North America	South America	Africa	Asia	Australasia	Total ^a	
		UK	Rest of Europe	US	Rest of North America					
Number of productive wells at 31 December 2022										
Oil wells ^b	– gross	108	122	1,248	7	5,231	839	2,580	–	10,135
	– net	60	19	702	2	2,579	77	566	–	4,005
Gas wells ^c	– gross	35	9	4,559	–	1,163	206	153	89	6,214
	– net	6	1	2,507	–	417	88	58	18	3,096
Oil and natural gas acreage at 31 December 2022										
thousands of acres										
Developed	– gross	69	98	1,811	8	1,298	1,374	1,315	840	6,813
	– net	40	16	1,039	1	367	389	271	148	2,270
Undeveloped ^d	– gross	666	172	3,876	9,339	12,302	22,107	5,925	10,260	64,647
	– net	492	27	3,260	5,971	5,595	9,189	1,863	7,121	33,518

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

^b Includes approximately 159 gross (28 net) multiple completion wells (more than one formation producing into the same well bore).

^c Includes approximately 125 gross (93 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.

^d 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			
2022											
Exploratory											
	Productive	–	–	0.5	1.0	1.0	0.6	–	0.5	0.3	4.0
	Dry	–	–	–	1.2	0.3	0.1	–	0.8	–	2.3
Development											
	Productive	0.9	1.5	137.2	0.3	71.4	2.8	–	39.0	1.4	254.5
	Dry	–	–	1.1	–	0.5	0.1	–	1.1	–	2.8
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

^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 2022. 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 2022									
Exploratory									
Gross	–	–	4.0	–	–	–	6.0	–	10.0
Net	–	–	2.8	–	–	–	0.6	–	3.4
Development									
Gross	3.0	2.6	185.0	–	22.0	15.0	122.0	11.0	360.6
Net	1.5	0.4	91.0	–	5.4	4.6	28.1	4.4	135.4

^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	2022	2021
Dividend income		29,005	851
Interest and other income		2,115	405
Total income		31,120	1,256
Administrative and other expenses		(563)	7
Net impairment of fixed asset investments	2	3,433	(1,109)
Profit (loss) before interest and taxation		33,990	154
Interest payable to subsidiaries		(3,567)	(531)
Net finance income (expense) relating to pensions	4	165	126
Profit (loss) before taxation		30,588	(251)
Taxation	6	(48)	(142)
Profit (loss) for the year		30,540	(393)

Company statement of comprehensive income

For the year ended 31 December		\$ million	
	Note	2022	2021
Profit (loss) for the year		30,540	(393)
Other comprehensive income			
Items that may be reclassified subsequently to profit or loss			
Currency translation differences		(1,037)	(111)
		(1,037)	(111)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension liability or asset	4	(1,530)	2,410
Income tax relating to items that will not be reclassified	6	931	(802)
		(599)	1,608
Other comprehensive income		(1,636)	1,497
Total comprehensive income		28,904	1,104

The parent company financial statements of BP p.l.c. on pages 291-349 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	2022	2021
Non-current assets			
Investments	2	165,483	159,662
Receivables	3	772	3,234
Defined benefit pension plan surpluses	4	7,716	10,281
		173,971	173,177
Current assets			
Receivables	3	10,646	320
Cash and cash equivalents		85	27
		10,731	347
		184,702	173,524
Total assets			
Current liabilities			
Payables	5	5,864	9,176
		4,867	(8,829)
Net current assets			
Total assets less current liabilities			
		178,838	164,348
Non-current liabilities			
Payables	5	53,489	53,658
Deferred tax liabilities	6	2,692	3,575
Defined benefit pension plan deficits	4	128	237
		56,309	57,470
		62,173	66,646
Total liabilities			
Net assets			
Capital and reserves^a			
Profit and loss account			
Brought forward		73,324	79,721
Profit (loss) for the year		30,540	(393)
Other movements		(15,323)	(6,004)
		88,541	73,324
Called-up share capital	7	4,795	5,215
Share premium account		13,692	12,745
Other capital and reserves		15,501	15,594
		122,529	106,878

^a See Statement of changes in equity on page 293 for further information.

The financial statements on pages 291-349 were approved and signed by the chief executive officer on 10 March 2023 having been duly authorized to do so by the board of directors:

Bernard Looney Chief executive officer

Company statement of changes in equity^a

								\$ million
	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Treasury shares	Foreign currency translation reserve	Profit and loss account	Total equity
At 1 January 2022	5,215	12,745	1,705	26,509	(12,623)	3	73,324	106,878
Profit (loss) for the year	—	—	—	—	—	—	30,540	30,540
Other comprehensive income	—	—	—	—	—	(1,037)	(599)	(1,636)
Total comprehensive income	—	—	—	—	—	(1,037)	29,941	28,904
Dividends	—	—	—	—	—	—	(4,365)	(4,365)
Repurchases of ordinary share capital ^a	(475)	—	475	—	—	—	(10,493)	(10,493)
Share-based payments, net of tax	14	168	—	—	469	—	134	785
New issue of ordinary share capital	41	779	—	—	—	—	—	820
At 31 December 2022	4,795	13,692	2,180	26,509	(12,154)	(1,034)	88,541	122,529
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	(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

^a See Note 7 for further information.

Notes on financial statements

1. Significant accounting policies, judgements, estimates and assumptions

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

The financial statements of BP p.l.c. for the year ended 31 December 2022 were approved and signed by the chief executive officer on 10 March 2023 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
- (j) 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 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 current economic and geopolitical environment, 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.

The parent company financial statements of BP p.l.c. on pages 291-349 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 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 recoverable amounts of the company's investments in subsidiaries are closely linked to the carrying value of property, plant and equipment and goodwill in the individual subsidiaries. The energy transition is likely to impact the future prices of commodities such as oil and natural gas which in turn may affect the recoverable amount of property, plant and equipment and goodwill in the oil and gas industry. Management's best estimate of oil and natural gas price assumptions for value-in-use impairment testing for all subsidiaries were revised during 2022. Prices disclosed are in real 2021 terms. The Brent oil assumption from 2024 up to 2030 was increased to \$70 per barrel to reflect near-term supply constraints before steadily declining to \$45 per barrel by 2050 continuing to reflect the assumption that as the energy system decarbonizes, falling oil demand will cause oil prices to decline. The price assumptions for Henry Hub gas up to 2035 and up to 2050 were increased to \$4.00 per mmBtu and \$3.50 per mmBtu respectively, reflecting increased demand for US gas production to offset reduced Russian gas flows. 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.

Judgements and estimates made in assessing the impact of the geopolitical and 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 current geopolitical and 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 151 to 262) 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 2022 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.

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

Significant judgements and estimates: recoverability of asset carrying values

Determination as to whether, and by how much, an 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 2022 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 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 2022 the pre-tax discount rate typically ranged from 7% to 18% (2021 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.

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 185. 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 (in real 2021 terms) for Brent oil assumption from 2024 up to 2030 was increased to \$70 per barrel to reflect near term supply constraints before steadily declining to \$45 per barrel by 2050 continuing to reflect the assumption that as the energy system decarbonises, falling oil demand will cause oil prices to decline. The price assumptions for Henry Hub gas up to 2035 and up to 2050 were increased to \$4 per mmBtu and \$3.50 per mmBtu respectively to reflect the increased demand for US gas production to offset reduced Russian gas flows. These price assumptions are derived from the central case investment appraisal assumptions, adjusted where applicable to reflect short-term market conditions (see page 28). A summary of the group's revised price assumptions for Brent oil and Henry Hub gas, applied in 2022 and 2021, in real 2021 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% (2021 2%) is applied to determine the price assumptions in nominal terms.

2022 price assumptions	2023	2025	2030	2040	2050
Brent oil (\$/bbl)	77	70	70	58	45
Henry Hub gas (\$/mmBtu)	4.00	4.00	4.00	3.50	3.50

2021 price assumptions	2022	2025	2030	2040	2050
Brent oil (\$/bbl)	71	61	61	56	46
Henry Hub gas (\$/mmBtu)	4.08	3.06	3.06	3.06	2.80

The parent company financial statements of BP p.l.c. on pages 291-349 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

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.

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.

The parent company financial statements of BP p.l.c. on pages 291-349 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

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.

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 income 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.

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2. Investments

	\$ million		
	Subsidiaries*	Associates	
	Shares	Shares	Total
Cost			
At 1 January 2022	166,760	9	166,769
Additions	2,388	—	2,388
At 31 December 2022	169,148	9	169,157
Amounts provided			
At 1 January 2022	7,107	—	7,107
Additions	—	—	—
Reversals	(3,433)	—	(3,433)
At 31 December 2022	3,674	—	3,674
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
At 31 December 2022	165,474	9	165,483
At 31 December 2021	159,653	9	159,662

At 31 December 2022, the carrying amount of the company's net assets of \$122.5 billion (2021 \$106.9 billion) exceeded the group's market capitalisation of \$105.8 billion (2021 \$88.1 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. Taking into account improvements in performance of the investments and the increase in headroom in impairment tests performed by the company's subsidiaries, which is largely attributable to the upward revision of short-term oil and natural gas prices, management concluded that there were no impairments in terms of a deterioration of value in use or fair value less costs to sell. It was also deemed appropriate based on the analysis to reverse previously recognized impairment provisions in respect of the company's investments in subsidiaries.

On 27 February 2022, bp announced it will exit its shareholding in Rosneft Oil Company (Rosneft) and bp's two nominated Rosneft directors both stepped down from Rosneft's board. While 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 has led to an impairment in the group consolidated financial statements (for additional information see page 188), the impairment tests outlined above do not indicate any impairment is required in respect of the BP International Limited holding chain (which owns the investment BP Russian Investments Limited which is the company that holds the investment in Rosneft) in the BP p.l.c. company financial statements.

The more important subsidiaries of the company at 31 December 2022 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 13.

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	Investment holding
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 2022 was \$76,281 million (2021 \$75,633 million).

3. Receivables

	\$ million			
	2022		2021	
	Current	Non-current	Current	Non-current
Amounts receivable from subsidiaries ^a	10,641	772	311	3,234
Amounts receivable from associates	3	—	6	—
Other receivables	2	—	3	—
	10,646	772	320	3,234

^a The 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 and disclosed in 2021 as non-current receivables was paid out to the company in 2022.

The company has current receivables of \$10,218 million on Internal Funding Accounts (IFAs) receivable from BP International Limited (2021 \$nil), following the receipt of dividends of \$29,005 million from various subsidiaries within the group. These balances form a key part of the bp group's liquidity and funding arrangements under its centralised treasury funding model. Whilst IFA credit balances are legally repayable on demand, in practice they have no termination date. IFA debit balances can also be accessed by BP International Limited at short notice.

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 chair 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. 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.

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 2022. The closure of the defined benefit plan to future accrual eliminated the need for funding in 2022, and 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 2022. The principal plans are subject to a formal actuarial valuation every 3 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 the accrued benefit obligation at 31 December and pension expense for the following year.

Financial assumptions used to determine benefit obligation ^a	%	
	2022	2021
Discount rate for plan liabilities	5.0	1.8
Rate of increase for pensions in payment	2.9	3.2
Rate of increase in deferred pensions	2.9	3.2
Inflation for plan liabilities	3.1	3.3

Financial assumptions used to determine benefit expense	%	
	2022	2021
Discount rate for plan service cost ^b	N/A	1.5
Discount rate for plan other finance expense ^c	1.8	1.7
Inflation for plan service cost ^b	N/A	2.8

^a Salary growth has not been a material financial assumption for the UK following the closure of the primary pension plan to future accrual in 2021. The rate of increase in salaries for the UK was 3.6% in 2020.

^b UK discount rate and inflation rate assumptions are not significant in determining the benefit expense following closure of the primary UK plan to future accrual in 2021. Rates for the remaining small worldwide plan administered and reported through the UK are 2.5% and 2.2% respectively.

^c The discount rate for plan other finance expense in 2021 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 where there is such an increase.

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:

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4. Pensions – continued

Mortality assumptions	Years	
	2022	2021
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	28.5	28.4
Life expectancy at age 60 for a female currently aged 60	28.8	28.9
Life expectancy at age 60 for a female currently aged 40	30.6	30.5

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

A significant proportion of the assets are held in equities, 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. During 2022, the asset allocation policy switched 2% of plan assets from equities to bonds (2021 5%).

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

Asset category	%
Total equity (including private equity)	10
Bonds/cash (including LDI)	83
Property/real estate	7

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2022 were \$3,981 million (2021 \$7,399 million) of government-issued nominal bonds and \$11,945 million (2021 \$24,516 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 303.

	\$ million	
	2022	2021
Fair value of pension plan assets		
Listed equities – developed markets	1,252	2,964
– emerging markets	117	252
Private equity ^a	2,715	3,233
Government issued nominal bonds ^b	4,039	7,491
Government issued index-linked bonds ^b	11,945	24,516
Corporate bonds ^b	6,317	10,128
Property ^c	2,297	2,714
Cash	567	1,136
Other	1,088	1,133
Debt (repurchase agreements) used to fund liability driven investments	(5,290)	(10,723)
	25,047	42,844

^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 or hedged back to sterling to minimize foreign currency exposure, and are predominantly valued using observable market data based inputs other than quoted market 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.

4. Pensions – continued

	\$ million	
	2022	2021
Analysis of the amount charged to profit or loss		
Current service cost ^a	41	154
Past service cost ^b	23	(302)
Settlement	(8)	–
Operating charge / (credit) relating to defined benefit plans	56	(148)
Payments to defined contribution plan	110	76
Total operating charge / (credit)	166	(72)
Interest income on plan assets ^c	(694)	(684)
Interest on plan liabilities	529	558
Other finance (income)	(165)	(126)
Analysis of the amount recognized in other comprehensive income		
Actual asset return less interest income on pension plan assets	(12,955)	2,440
Change in financial assumptions underlying the present value of the plan liabilities	11,528	(103)
Change in demographic assumptions underlying the present value of plan liabilities	46	66
Experience gains and losses arising on the plan liabilities	(149)	7
Remeasurements recognized in other comprehensive income	(1,530)	2,410

^a The costs of managing plan investments are offset against the investment return. Following the closure of the main UK pension plan to future accrual, current service cost consists of \$30 million of the costs of administering the pension plan and \$11 million of current service cost from the remaining small worldwide schemes administered and reported through the UK.

^b Past service costs predominantly represent historical benefits reinstated as part of a creation of a new plan in the UK for former Turkish pension plan members.

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

4. Pensions – continued

	\$ million	
	2022	2021
Movements in benefit obligation during the year		
Benefit obligation at 1 January	32,800	34,132
Exchange adjustments	(3,220)	(254)
Operating charge relating to defined benefit plans	56	(148)
Interest cost	529	558
Contributions by plan participants	9	18
Benefit payments (funded plans) ^a	(1,211)	(1,530)
Benefit payments (unfunded plans) ^a	(5)	(6)
Disposals	(74)	–
Remeasurements	(11,425)	30
Benefit obligation at 31 December	17,459	32,800
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	42,844	41,463
Exchange adjustments	(4,258)	(365)
Interest income on plan assets ^b	694	684
Contributions by plan participants	9	18
Contributions by employers (funded plans)	10	134
Benefit payments (funded plans) ^a	(1,211)	(1,530)
Disposals	(86)	–
Remeasurements ^b	(12,955)	2,440
Fair value of plan assets at 31 December ^{c,d}	25,047	42,844
Surplus at 31 December	7,588	10,044
Represented by		
Asset recognized	7,716	10,281
Liability recognized	(128)	(237)
	7,588	10,044
The surplus may be analysed between funded and unfunded plans as follows		
Funded	7,716	10,281
Unfunded	(128)	(237)
	7,588	10,044
The defined benefit obligation may be analysed between funded and unfunded plans as follows		
Funded	(17,331)	(32,563)
Unfunded	(128)	(237)
	(17,459)	(32,800)

^a The benefit payments amount shown above comprises \$1,185 million benefits (2021 \$1,507 million) plus \$31 million (2021 \$29 million) of plan expenses incurred in the administration of the benefit.

^b 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.

^c Reflects \$24,788 million of assets held in the BP Pension Fund (2021 \$42,459 million) and \$202 million held in the BP Global Pension Trust (2021 \$319 million), as well as \$44 million representing the company's share of Merchant Navy Officers Pension Fund (2021 \$51 million) and \$13 million of Merchant Navy Ratings Pension Fund (2021 \$15 million).

^d The fair value of plan assets includes borrowings related to the LDI programme as described on page 301.

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 2022 for the company's plans would have had the effects shown in the table below. The effects shown for the expense in 2023 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 2023	(200)	180
Effect on pension obligation at 31 December 2022	(2,041)	2,550
Inflation rate^b		
Effect on pension expense in 2023	82	(77)
Effect on pension obligation at 31 December 2022	1,646	(1,531)

^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 2023 pension expense by \$25 million and the pension obligation at 31 December 2022 by \$503 million.

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, and the weighted average duration of the defined benefit obligations at 31 December 2022 are as follows:

	\$ million
Estimated future benefit payments	
2023	983
2024	1,014
2025	1,021
2026	1,033
2027	1,046
2028-2032	5,363
	Years
Weighted average duration	13.0

5. Payables

	2022		2021	
	Current	Non-current	Current	Non-current
Amounts payable to subsidiaries	5,230	53,358	9,084	53,606
Accruals	498	8	2	—
Other payables	136	123	90	52
	5,864	53,489	9,176	53,658

Included in current amounts payable to subsidiaries is an interest-bearing payable of \$5,069 million (2021 \$5,032 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 \$83 million on IFAs payable to BP International Limited (2021 \$4,023 million) (see also Note 3 - Receivables).

Non-current amounts payable to subsidiaries includes an interest-bearing payable of \$52,585 million with BP International Limited issued in December 2021 (2021 \$52,585 million), with interest being charged based on a 3-month USD LIBOR rate plus 75 basis points and a maturity date of December 2028. This \$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's 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.

	2022		2021	
Due within				
1 to 2 years	60		40	
2 to 5 years	224		179	
More than 5 years	53,205		53,439	
	53,489		53,658	

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6. Taxation

	\$ million	
	2022	2021
Tax charge included in total comprehensive income		
Deferred tax		
Origination and reversal of temporary differences in the current year	(883)	944
This comprises:		
Taxable temporary differences relating to pensions	(883)	944
Deferred tax		
Deferred tax liability		
Pensions	2,692	3,575
Net deferred tax liability	2,692	3,575
Analysis of movements during the year		
At 1 January	3,575	2,631
Charge (credit) for the year in the income statement	48	142
Charge (credit) for the year in other comprehensive income	(931)	802
At 31 December	2,692	3,575

At 31 December 2022, deferred tax assets of \$909 million on other temporary differences; \$8 million relating to pensions, \$119 million relating to income losses and \$782 million relating to other deductible temporary differences (2021 \$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) 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:

	2022		2021	
	Shares thousand	\$ million	Shares thousand	\$ million
Issued				
8% cumulative first preference shares of £1 each ^a	7,233	12	7,233	12
9% cumulative second preference shares of £1 each ^a	5,473	9	5,473	9
		21		21
Ordinary shares of 25 cents each				
At 1 January	20,778,082	5,194	21,449,782	5,362
Issue of new shares for employee share-based payment plans	55,000	14	35,001	9
Issue of new shares - other	165,105	41	—	—
Repurchase of ordinary share capital	(1,900,404)	(475)	(706,701)	(177)
At 31 December	19,097,783	4,774	20,778,082	5,194
		4,795		5,215

^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 2022 the company repurchased 1,900 million ordinary shares for a total consideration of \$9,996 million, including transaction costs of \$54 million, as part of the share repurchase programme announced on 27 April 2021. All shares purchased were for cancellation. The repurchased shares represented 10.0% of ordinary share capital. A further 107 million ordinary shares were repurchased between the end of the reporting period and 17 February 2023, the latest practicable date before the completion of these financial statements, for a total cost of \$653 million of which \$497 million has been accrued at 31 December 2022. The number of shares in issue is reduced when shares are repurchased.

165 million new ordinary shares were issued in April 2022 as non-cash consideration for the acquisition of the public units of BP Midstream Partners LP.

7. Called-up share capital – continued

Treasury shares^a

	2022		2021	
	Shares thousand	Nominal value \$ million	Shares thousand	Nominal value \$ million
At 1 January	1,137,457	283	1,187,650	296
Purchases for settlement of employee share plans	14,150	4	1,432	—
Issue of new shares for employee share-based payment plans	55,000	14	35,096	9
Shares re-issued for employee share-based payment plans	(81,680)	(20)	(86,721)	(22)
At 31 December	1,124,927	281	1,137,457	283
Of which - shares held in treasury by bp	940,571	235	1,037,201	259
- shares held in ESOP trusts	184,356	46	100,256	24

^a See Note 8 for definition of treasury shares.

^b Held by the company in the form of ADSs to meet the requirements of employee share-based payment plans in the US.

For each year presented, the balance of shares held in treasury by bp at 1 January represents 5.0% (2021 5.2%) of the called-up ordinary share capital of the company.

During 2022, the movement in shares held in treasury by bp represented less than 0.5% (2021 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 \$23,610 million (2021 \$24,107 million), the distribution of which is limited by statutory or other restrictions.

The financial statements for the year ended 31 December 2022 do not reflect the dividend announced on 7 February 2023 which will be paid in March 2023; this will be treated as an appropriation of profit in the year ended 31 December 2023.

The parent company financial statements of BP p.l.c. on pages 291-349 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

9. Financial guarantees and other contingencies

The company has issued guarantees to third parties and other bp subsidiaries in case of the failure, on the part of certain bp subsidiaries, to pay current liabilities and obligations pertaining to business operations. The amounts guaranteed by the company, at 31 December 2022, for these arrangements is \$107 million (2021^a \$32 million). The company guarantees finance debt and lease obligations of certain bp group subsidiaries. Maturity dates vary and guarantees will terminate on full payment and/or cancellation of the obligation. As of 31 December 2022, maximum guaranteed amounts pertaining to debt and lease arrangements were \$57,265 million (2021^a \$58,322 million). These maximum amounts are more than the actual guaranteed exposure due at the balance sheet date as well as more than remaining obligations under the guaranteed contracts.

Performance under all the above guarantees would be triggered by a financial default of the guaranteed entity and, as such, are currently not expected to have any material effect.

As part of normal ongoing business operations and consistent with generally accepted industry practices, the company also executes contracts involving standard indemnities and guarantees for the respective businesses in which bp operates as well as indemnities specific to transactions, including the sale of businesses. This includes a guarantee 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 guarantees for certain subsidiaries' liabilities under the Plaintiffs' Steering Committee agreement relating to the Gulf of Mexico oil spill. See Note 33 in the consolidated group financial statements of BP p.l.c. for further information. The company regularly evaluates the probability of having to incur costs associated with these indemnities and does not believe such matters will have a material adverse effect on its results of operations and cash flow.

In addition, BP plc guarantees \$11.9 billion of perpetual subordinated hybrid bonds issued by a subsidiary.

The company believes that guarantees and other off-balance sheet commitments do not currently, nor could reasonably have in the future, a material effect on its financial position, income and expenses, liquidity, investments or financial resources.

^a The prior years comparatives have been amended.

10. Auditor's remuneration

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

11. Directors' remuneration

	\$ million	
	2022	2021
Remuneration of directors		
Total for all directors		
Emoluments	8	9
Amounts awarded under incentive schemes ^a	13	4
Total	21	13

^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 112.

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

12. Employee costs and numbers

	\$ million	
	2022	2021
Employee costs		
Wages and salaries	924	696
Social security costs	131	91
Pension costs	—	50
	1,055	837
Average number of employees		
gas & low carbon energy	329	276
oil production & operations	187	161
customers & products	1,182	1,039
other businesses and corporate	1,893	1,772
	3,591	3,248

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

The parent company financial statements of BP p.l.c. on pages 291-349 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group

In accordance with Section 409 of the Companies Act 2006, a full list of related undertakings, showing the registered office address and the effective equity owned by the bp group as at 31 December 2022 is disclosed below.

Unless otherwise stated, all interests 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.

Subsidiaries

Company by country of incorporation and registered office address	Ownership interest	%
Albania		
Bruga Ibrahim Rugova, Sky Tower, Tirana, Kati 9/1, Albania BP Albania SHPK	Ordinary	100.00
Argentina		
Av. Cordoba 315 Piso 8, Buenos Aires, 1054, Argentina Latin Energy Argentina S.A.	Ordinary	100.00
Australia		
Level 11, 307 Queen Street, Brisbane, QLD, 4000, Australia Onyx Insight Australia Pty Ltd	Ordinary	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 ^a	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 Alternative Energy Australia Pty Ltd	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 ^c	Ordinary	100.00
BP Australia Supply Pty Ltd	Ordinary	100.00
BP Bulwer Island Pty Ltd	Ordinary; Ordinary A; Ordinary B	100.00
BP Energy Australia Pty Ltd	Ordinary	100.00
BP Finance Australia Pty Ltd	Ordinary	100.00
BP Low Carbon Australia (CCS) Pty Ltd	Ordinary	100.00
BP Low Carbon 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
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	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
No. 1 Riverside Quay Proprietary Limited	Ordinary	100.00
Open Energi Australia Pty Ltd	Ordinary; Ordinary A	100.00
Taradadis Pty. Ltd.	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 291-349 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

West Kimberley Fuels Pty Ltd	Ordinary	100.00
Austria		
Am Belvedere 10, 1100 Wien, 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
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, 4th floor, rooms 43A and 44A , Tower C, Building Landmark, Brooklin Paulista, São Paulo, 04578-000, Brazil		
Air BP Brasil Ltda.	Ordinary	100.00
BP Biocombustíveis S.A.	Ordinary	100.00
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		
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
1700, 421 – 7th Avenue SW Calgary, AB T2P 4K9, Canada		
Finite Carbon Canada LTD	Ordinary	80.50
240 - 4th Avenue SW, Calgary AB T2P 4H4, Canada		
563916 Alberta Ltd.	Preference	99.90
Dome Beaufort Petroleum Limited	Ordinary	100.00
Dome Wallis (1980) Limited Partnership	Partnership interest	92.50
Fotech Solutions (Canada) Ltd.	Membership Interest	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

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13. Related undertakings of the group – continued

808-02, Building 2, No.16, Xingao Road, Niutang Town, Wujin District, Changzhou City, Jiangsu Province, China Changzhou BP Xiaoju New Energy 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
F3-DC8098, Red Star Macalline Forehead Bay Shopping Mall, Jin Street Independent Store, No. 3 Yuanboyuan Road, Qiaokou District, Wuhan City, China Wuhan BP Xiaoju New Energy Technology 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.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
Office 6, Room 708, No. 33 Jinmeng Lane, Xiangzhou District, Zhuhai City, Guangdong Province, China Zhuhai BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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 102, No. 1, Qiao Jie Shi Xin Road, Guangzhou, China Guangzhou Jintian New Energy Technology Co., Ltd.	Ordinary	100.00
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, 2nd floor, Building 3, Industrial Research and Development, Xingong Standard Factory Building, No. 31, Songbai Road, Santang Town, Xingning District, Nanning City, Guangxi Province, China Nanning BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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 215, Building 5, No. 72, Nanxiang 2nd Road, Sciecheng, Huangpu District, Guangzhou, China Guangzhou Jintian Linkage New Energy Technology Co., Ltd.	Ordinary	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
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

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13. Related undertakings of the group – continued

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 402, 4F, Block C, Complex Building, No.30 Jiefang Road, Lixia District, Jinan City, Shandong Province, China Jinan 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 431, No. 30, East Qilong Road, Guangzhou, China Guangdong Jintian Technology Co., Ltd.	Ordinary	100.00
Room 6, Ground floor, Building A, No.2 Taohong West Street, Shima Village, Junhe Street, Baiyun District, Guangzhou, China Guangdong Jintian New Energy Automobile Co., Ltd.	Ordinary	100.00
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
Room D416, No.183, Hongming Road, Lilian Street, Huangpu District, Guangzhou City, China Guangzhou Huangpu BP Xiaoju New Energy Technology 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
Unit 1901, Nominal Floor 19 (Actual Floor 17), No. 76 Pujian Road, Shangai, Pilot Free Trade Zone, China Onyx Insight Analytics Shanghai Limited	Membership Interest	100.00
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
	Ordinary	100.00
Egypt		
Plot No 14d03, The Southern Business district of Cairo, Festival City - New Cairo, Cairo, Egypt BP Marketing Egypt LLC	Ordinary	100.00
Castrol Egypt Lubricants S.A.E.	Ordinary	51.00
Castrol Egypt Marketing SSC	Ordinary	100.00
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

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13. Related undertakings of the group – continued

Société de Gestion de Dépôts 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
Sportallee 6, 22335 Hamburg, Germany		
TGH Tankdienst-Gesellschaft Hamburg GbR	Partnership interest	66.67
Timmerhellstr. 28, Mülheim/Ruhr, 45478, Germany		
DHC Solvent Chemie GmbH	Ordinary	100.00
Überseeallee 1, 20457, Hamburg, Germany		
BP Europa SE ^d	Ordinary	100.00
BP Lingen Green Hydrogen Verwaltung GmbH	Ordinary	100.00
BP Olex Fanal Mineralöl 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
Trafineo Service GmbH	Ordinary	75.00
Wittener Straße 56, Bochum, Germany		
TRaBP GbR	Partnership interest	75.00
Trafineo GmbH & Co. KG	Partnership interest	75.00
Trafineo Verwaltungs-GmbH	Ordinary	75.00
Zum Ölhafen 207, 26384 Wilhelmshaven, Germany		
Nord-West Oelleitung GmbH	Ordinary	59.33
Ghana		
Atlantic Tower, 4th Floor, Liberation Road, Airport City, Accra, Ghana		
BP Ghana Ltd	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 ^e	Ordinary	100.00
Jupiter Insurance Limited	Ordinary	100.00
Hong Kong		
21/F Edinburgh Tower, 15 Queen's Road Central, Hong Kong		
BP Hong Kong Limited	Ordinary	100.00
Unit 25-150, 25/F, Two Harbour Square, 180 Wai Yip Street, Kwun Tong, Kowloon, Hong Kong		
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
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

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13. Related undertakings of the group – continued

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	88.51
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
3rd Floor, 10, Baumoe-ro 21-gil, Seocho-gu, Seoul, Korea (the Republic of)		
Onyx Insight Korea Co., Ltd.	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		
Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico		
BP Energía México, S. de R.L. de C.V.	Ordinary; Ordinary B	100.00
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

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13. Related undertakings of the group – continued

Mozambique		
Torres Rani, Avenida Marginal, Talhão 141, 6º andar, Maputo, Mozambique		
BP Mocambique Limitada	Ordinary	100.00
Netherlands		
Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, England, United Kingdom		
BP Capital Markets B.V.	Ordinary	100.00
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 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 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
Vaals B.V.	Ordinary	100.00
Vaals HoldCo B.V.	Ordinary	100.00
Vaals TopCo B.V.	Ordinary	100.00
Überseeallee 1, 20457, Hamburg, Germany		
BP Holdings Central Europe 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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13. 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		
37th Floor, LKG Tower 6801, Ayala Avenue, Makati City, Philippines		
Castrol Philippines, Inc.	Ordinary	100.00
Poland		
ul. Grzybowska 62, Warszawa, 00-844, Poland		
Castrol CEE spółka 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		
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
Otopeni, 224E Calea Bucurestilor, within International Airport - Băneasa, Aurel Vlaicu - platform 2, Ilfov county, Romania		
Air BP Sales Romania S.R.L.	Ordinary	100.00
Russian Federation		
121099, Moscow, Arbat Municipal District, Smolenskaya square 3, floor 7, office 717 Russian Federation		
Limited liability company Setra Lubricants	Membership Interest	100.00
121099, Moscow, Arbat Municipal District, Smolenskaya square 3, floor 7, office 767, working place 3, Russian Federation		
OOO BP STL - in liquidation	Membership Interest	100.00
Smolenskaya Square 3, Floor 7, Office 767, Moscow, 121099, Russian Federation		
Limited Liability Company BP Toplivnaya Kompania - in liquidation	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 ^a	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
Slovakia		
Karadžičova 2, Bratislava, 815 32, Slovakia		
Blueprint Power Slovakia s.r.o.	Membership Interest	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

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13. Related undertakings of the group – continued

Spain		
Atraque Punta Lucero, Explanada Punta Ceballos s/n, Ziórbena (Vizcaya), Spain		
Bahia de Bizkaia Electricidad, S.L.	Ordinary	75.00
Calle Quintanadueñas, 6, (Edificio Arqboarea), Madrid, 28050, 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 & Power Iberia, S.A	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 Energía España, S.A. Unipersonal	Ordinary	100.00
Sweden		
Box 8107, Stockholm, 10420, Sweden		
Air BP Sweden AB	Ordinary	100.00
Hemvärnsgatan, 171 54, Solna, Sweden		
Castrol Sweden AB	Ordinary	100.00
Switzerland		
Baarendstrasse 139, Zug, 6300, Switzerland		
Castrol Switzerland GmbH	Ordinary	100.00
Taiwan (Province of China)		
57F.-1, No. 7, Sec. 5, Xinyi Rd., Xinyi Dist., Taipei City, 11049, Taiwan (Province of China)		
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
Türkiye		
Degirmen yolu cad. No:28, Asia OfisPark K:3 Icerenkoy-Atasehir, Istanbul, 34752, Türkiye		
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, Türkiye		
Castrol Madeni Yağlar Ticaret Anonim Şirketi	Ordinary	100.00
United Arab Emirates		
2474ResCo-work07 & 2474ResCo-work08, 24, Al Sila Tower, Abu Dhabi Global Market Square, Al Maryah Island, Abu Dhabi, United Arab Emirates		
LYTT ME LIMITED	Ordinary	100.00
8th Floor, Standard Chartered Tower, Downtown, Dubai, United Arab Emirates		
BP Middle East LLC	Ordinary	100.00
Cloud Suite 214, 15th Floor, Al Sarab Tower, ADGM Square, Al Maryah Island, Abu Dhabi, United Arab Emirates		
FOTECH ME LIMITED	Ordinary	100.00
Jebel Ali Free Zone, Dubai, United Arab Emirates		
Stryde Middle East FZE	Ordinary	100.00

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13. Related undertakings of the group – continued

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 ^a	Ordinary	100.00
10 Upper Berkeley Street, London, W1H 7PE, United Kingdom		
Horizon 38 Management Company Limited	Membership Interest	53.50
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
Bdo LLP, 4 Atlantic Quay, 70 York Street, Glasgow, G2 8JX, United Kingdom		
The Burmah Oil Company (Pakistan Trading) Limited	Ordinary	100.00
Breckland, Linford Wood, Milton Keynes, MK14 6GY, 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 Chemicals East China Investments Limited	Ordinary	100.00
BP Exploration (Canada) Limited	Ordinary	100.00
BP Exploration (Greenland) Limited	Ordinary	100.00
BP Exploration (Madagascar) Limited	Ordinary	100.00
BP Exploration (Namibia) Limited	Ordinary	100.00
BP Exploration Peru Limited	Ordinary	100.00
BP Petrochemicals India Investments Limited	Ordinary	100.00
BP Subsea Well Response (Brazil) Limited	Ordinary	100.00
Expandite Contract Services Limited	Ordinary	100.00
Exploration (Luderitz Basin) Limited	Ordinary	100.00
Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, England, 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
Autino Holdings Limited	Ordinary	100.00
Autino Limited	Ordinary	100.00
BP (Abu Dhabi) Limited	Ordinary	100.00
BP (Barbican) Limited ^a	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 ^a	Ordinary	100.00
BP Absheron Limited	Ordinary	100.00
BP Advanced Mobility Limited	Ordinary	100.00
BP Africa Limited ^a	Ordinary	100.00
BP Africa Oil Limited	Ordinary	100.00
BP Agung I Limited	Ordinary	100.00
BP Agung II 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

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13. Related undertakings of the group – continued

BP Asia Pacific Holdings Limited	Ordinary	100.00
BP Australia Swaps Management Limited	Ordinary	100.00
BP Benevolent Fund Trustees Limited ^a	Ordinary	100.00
BP Biofuels Brazil Investments Limited	Ordinary	100.00
BP Capital Markets p.l.c.	Ordinary	100.00
BP Car Fleet Limited ^a	Ordinary	100.00
BP Carbon Trading Limited	Ordinary	100.00
BP CCUS UK LTD	Ordinary	100.00
BP Chemicals Limited	Ordinary	100.00
BP Continental Holdings Limited	Ordinary	100.00
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	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 (Morocco) 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 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 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 ^a	Ordinary	100.00
BP Global Solutions Limited	Ordinary	100.00
BP Greece Limited	Ordinary	100.00
BP Holdings Canada Limited ^a	Ordinary	100.00
BP Holdings Iraq Ltd	Ordinary	100.00
BP Holdings North America Limited ^a	Ordinary; Cumulative redeemable preference	100.00
BP Indonesia Investment Limited	Ordinary	100.00
BP Integrated Solutions Limited	Ordinary	100.00
BP International Limited ^a	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

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13. Related undertakings of the group – continued

BP Mauritania Investments Limited	Ordinary	100.00
BP Middle East Limited ^a	Ordinary	100.00
BP Mocambique Limited	Ordinary	100.00
BP New Ventures Middle East Limited	Ordinary	100.00
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 ^a	Ordinary	100.00
BP Pensions Limited ^a	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 ^a	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 ^a	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 ^a	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
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
H2 Teesside Limited	Ordinary	100.00
Insight Analytics Solutions Holdings Limited	Ordinary	100.00

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13. Related undertakings of the group – continued

Insight Analytics Solutions Limited	Ordinary	100.00
Iraq Petroleum Company Limited	Ordinary	100.00
Kenilworth Oil Company Limited ^a	Ordinary	100.00
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
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 ^a	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	Currently exercisable options	63.00
Technology Centre, Whitchurch Hill, Pangbourne, Reading, RG8 7QR, United Kingdom		
Castrol Limited	Ordinary	100.00
United States		
100 Shockoe Slip, 2nd Floor, Richmond, VA, 23219, United States		
Collegiate Clean Energy, LLC	Membership Interest	100.00
INGENCO Wholesale Power, L.L.C.	Membership Interest	100.00
112 SW 7th Street, Suite 3C, Topeka, Kansas, 66603, United States		
Flat Ridge Wind Energy, LLC	Membership Interest	100.00
1201 Hays Street Tallahassee, FL, 32301		
Landfill Energy Systems Florida LLC	Membership Interest	100.00
1209 Orange Street, Wilmington DE 19801, United States		
200 PS Overseas Holdings 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 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 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

The parent company financial statements of BP p.l.c. on pages 291-349 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Amoco Rio Grande Pipeline Company	Ordinary	100.00
Amoco Somalia Petroleum Company	Ordinary	100.00
Amoco Sulfur Recovery Company	Ordinary	100.00
Amoco Tri-States NGL Pipeline Company	Ordinary	100.00
Amprop, Inc.	Ordinary	100.00
Anaconda Arizona, Inc.	Ordinary	100.00
Archaea Energy 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 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	100.00
BP Egypt Company	Ordinary	100.00
BP Energy Company	Ordinary	100.00
BP Energy Holding Company LLC	Membership Interest	100.00
BP Energy Retail Company California LLC	Membership Interest	100.00
BP Energy Retail Company LLC	Membership Interest	100.00
BP Exploration & Production Inc.	Ordinary; Preference	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

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13. Related undertakings of the group – continued

BP Midstream Partners LP	Ordinary	100.00
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 Pulse Fleet North America Inc.	Ordinary	100.00
BP River Rouge Pipeline Company LLC	Partnership interest	100.00
BP SC Holdings LLC	Membership Interest	100.00
BP Scale Up Factory North America Inc.	Ordinary	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	100.00
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 (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
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
Clean Eagle RNG, LLC	Membership Interest	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
Flat Ridge 2 Wind Energy LLC	Membership Interest	100.00
Flat Ridge 2 Wind Holdings LLC	Membership Interest	100.00
Flat Ridge Interconnection 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
Fowler Ridge 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
LFG Acquisition Holdings LLC	Membership Interest	100.00
Lightning Renewables, LLC	Membership Interest	60.00

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13. Related undertakings of the group – continued

Mardi Gras Transportation System Company LLC	Membership Interest	100.00
Mavrix, LLC	Membership Interest	100.00
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
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
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
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
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

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13. Related undertakings of the group – continued

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
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
211 E. 7th Street, Suite 620, Austin, TX, 78701, United States		
Gulf Coast Environmental Systems, LLC (dba Conifer Systems LLC)	Membership Interest	100.00
Toro Energy of Indiana, LLC	Membership Interest	60.00
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
251 Little Falls Drive, Wilmington, DE 19808, United States		
AH Medora LFG, LLC	Membership Interest	100.00
AHJRLFG, LLC	Membership Interest	100.00
AHMLFG, LLC	Membership Interest	100.00
Archaea AD, LLC	Membership Interest	100.00
Archaea CCS LLC	Membership Interest	100.00
Archaea Energy II LLC	Membership Interest	100.00
Archaea Energy Marketing LLC	Membership Interest	100.00
Archaea Energy Operating LLC	Membership Interest	100.00
Archaea Energy Services LLC	Membership Interest	100.00
Archaea Holdings, LLC	Membership Interest	100.00
Archaea Infrastructure, LLC	Membership Interest	100.00
Archaea Lutum, LLC	Membership Interest	100.00
Archaea Operating LLC	Membership Interest	100.00
Archaea Real Estate Holdings LLC	Membership Interest	100.00
Archaea Ventures LLC	Membership Interest	100.00
Aria Energy East LLC	Membership Interest	100.00
Aria Energy LLC	Membership Interest	100.00
Aria Energy Operating LLC	Membership Interest	100.00
Assai Energy, LLC	Membership Interest	100.00
Aurum Renewables LLC	Membership Interest	100.00
Biofuels Coyote Canyon Biogas, LLC	Membership Interest	100.00
BioFuels San Bernardino Biogas, LLC	Membership Interest	100.00
CES Biogas LLC	Membership Interest	100.00
Cefari RNG OKC, LLC	Membership Interest	100.00
CII Methane Holdings III, LLC	Membership Interest	100.00
CII Methane Holdings, LLC	Membership Interest	100.00
CII Methane Management III, LLC	Membership Interest	100.00
CII Methane Management IV, LLC	Membership Interest	100.00
Eagle Point RNG LLC	Membership Interest	100.00
EIF Innovative Holdings, LLC	Membership Interest	100.00
EIF KC Landfill Gas Holdings, LLC	Membership Interest	100.00
EIF KC Landfill Gas, LLC	Membership Interest	100.00
Element Markets Renewable Natural Gas, LLC	Membership Interest	100.00
Emerald City Renewables LLC	Membership Interest	100.00

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13. Related undertakings of the group – continued

Green Meadows Operations LLC	Membership Interest	100.00
Industrial Power Generating Company, LLC	Membership Interest	100.00
INGENCO Renewable Development LLC	Membership Interest	100.00
Innovative Energy Systems, LLC	Membership Interest	100.00
Innovative/Colonie, LLC	Membership Interest	100.00
Innovative/DANC, LLC	Membership Interest	100.00
Innovative/Fulton, LLC	Membership Interest	100.00
IPGC Holdings LLC	Membership Interest	100.00
JL-E Financial Holdings LLC	Membership Interest	100.00
LES Development LLC	Membership Interest	100.00
LES Manager LLC	Membership Interest	100.00
LES Operations Services LLC	Membership Interest	100.00
LES Renewable NG LLC	Membership Interest	100.00
LFG Holdings LLC	Membership Interest	100.00
NextGen Power Holdings LLC	Membership Interest	100.00
RNG Moovers LLC	Class B Membership Interest	95.00
Rochelle Energy LLC	Membership Interest	100.00
South Shelby RNG, LLC	Membership Interest	100.00
Southeast OKC RNG LLC	Membership Interest	100.00
Timberline Energy, LLC	Class A Membership Interest	100.00
Zeus Renewables LLC	Membership Interest	100.00
Zimmerman Energy LLC	Membership Interest	100.00
2595 Interstate Drive, Suite 103, Harrisburg, PA 17110		
PEI Power II, LLC	Membership Interest	100.00
PEI Power LLC	Membership Interest	100.00
2626 Glenwood Avenue, Suite 550, Raleigh, NC, 27608, United States		
Big Run Power Producers, LLC	Membership Interest	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
2900 West Road STE 500, East Lansing, MI, 48823		
Canton Renewables, LLC	Membership Interest	100.00
2908 Poston Avenue, Nashville, TN 37203		
CERF Shelby, LLC	Membership Interest	100.00
Tennessee Renewable Group LLC	Membership Interest	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
334, North Senate Avenue, Indianapolis, IN, 46204-1708, United States		
BP Corporation North America Inc.	Ordinary	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

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13. Related undertakings of the group – continued

701 South Carson Street Suite 200, Carson City, NV, 89701, United States Amoco Marketing Environmental Services Company	Ordinary	100.00
80 State Street, Albany, NY Model City Energy, LLC	Membership Interest	100.00
Modern Innovative Energy, LLC	Membership Interest	100.00
Seneca Energy II, LLC	Membership Interest	100.00
814 Thayer Avenue, Bismarck, ND, 58501-4018, United States The Anaconda Company	Ordinary	100.00
8585 Old Dairy Rd STE 208, Juneau, AK, 99801, AK, 99801 Frontier Operation Services, LLC	Membership Interest	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
Venezuela		
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. - in liquidation	Ordinary	100.00
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 Petroleo y Gas, S.A.	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

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13. Related undertakings of the group – continued

Related undertakings other than subsidiaries

Company by country of incorporation and registered office address	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	50.00
Argentina		
Av. Leandro N. Alem 1180, piso 11°, Buenos Aires, Argentina		
Field Services Enterprise S.A.	Ordinary	50.00
Pan American E&P 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
Avda. Leandro N. Alem 1180, Buenos Aires 1001, Argentina		
Lithos Desarrollos Energeticos S.A.	Ordinary	50.00
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
RSE & RCE S.A.U.	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 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
34 Kent Road, Mascot, NSW 2020, Australia		
5B Holdings Pty Limited	Preference Series B (27.47%)	9.80
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 Yarrowonga Development Pty Ltd	Ordinary	49.97
Lightsource Asset Management Australia Pty Ltd	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 Labs Australia Pty Limited	Ordinary	49.97
Lightsource LS Labs Australia Operations Pty Ltd	Ordinary	49.97
Lightsource Renewable Energy (Australia) Pty Ltd	Ordinary	49.97
Lower Wonga Solar Farm Pty Ltd	Ordinary	49.97
LS Australia Equity HoldCo1 Pty Ltd	Ordinary	49.97
LS Australia FinCo 1 Pty Ltd	Ordinary	49.97
LS Australia FinCo 2 Pty Ltd	Ordinary	49.97
LS Australia FinCo 3 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

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13. Related undertakings of the group – continued

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
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 16, Alluvion Building, 58 Mounts Bay Road, Perth, WA, Australia		
North West Shelf Lifting Coordinator Pty Ltd	Ordinary B (100.00%)	16.67
Level 3, Unit 3, 22 Albert Road, South Melbourne VIC 3205, Australia		
Australian Terminal Operations Management Pty Ltd	Ordinary	50.00
Suite 8.02, 28 O'Connell Street, Sydney, NSW 2000, Australia		
XPANSIV Limited	Preference Series A (26.16%)	19.34
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		
Erdöl-Lagergesellschaft m.b.H.	Membership Interest	23.00
Trabrennstraße 6-8 3, Wien, A-1020, 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 (Plurinational State of)		
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
Alameda Santos, N° 74, 7° Andar -, Conj. 72 - Sala 43 - Cerqueira Cesar -, São Paulo - SP -, C.E.P.: 01418-0		
Lightsource Bom Lugar Holding 2 S.A.	Ordinary	49.97
Lightsource Brasil Energia Renovável Ltda	Ordinary	49.97
Av. Bernardino de Campos, n. 98., Conj. A, 12 Andar, Sala 37, Paraíso, São Paulo, 04.004-040, Brazil		
Lightsource Brasil Energia Renovável Participações S.A.	Ordinary	49.97
Avenida Atlântica, no. 1.130, 2nd floor (part), Copacabana,RJ, Rio de Janeiro, 22021-000, Brazil		
NFX Combustíveis Marítimos Ltda.	Ordinary	50.00
Avenida das Nações Unidas, No. 12.399, 4th floor, complexo 41B, room 01, Building Landmark, Brooklin Paulista, São Paulo/ SP, 04578-000, Brazil		
BP Biofuels Trading Comércio, Importação e Exportação Ltda.	Ordinary	50.00
Avenida das Nações Unidas, n° 12.399, 4° andar, Brooklin Paulista, São Paulo, CEP 04578-000, Brazil		
BP Bunge Bioenergia S.A.	Ordinary	50.00

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13. Related undertakings of the group – continued

Avenida Paris, 4077, Suite 3, Cascata, São Paulo State, Paulínia, 13046-061, Brazil		
Terminal de Combustíveis Paulínia S.A.	Ordinary	50.00
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	50.00
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	50.00
Fazenda Guariroba, SN, Zona Rural, Pontes Gestal, São Paulo, 15500-000, Brazil		
Usina Guariroba Ltda.	Ordinary	50.00
Fazenda Moema, s/n, Rural, Orindiuva, São Paulo, 15480-000, Brazil		
Bunge Açúcar e Bioenergia S.A.	Ordinary	50.00
Fazenda Recanto, Zona Rural, CEP 38.300-898, Minas Gerais, Ituiutaba, Brazil		
BP Bioenergia Ituiutaba Ltda.	Ordinary	50.00
Fazenda Santa Bárbara, S/N, Distrito de Zelândia, Santa Juliana, Minas Gerais, 38175-000, Brazil		
Santa Juliana Bioenergia Ltda.	Ordinary	50.00
Fazenda São Bento da Ressaca, S/N, Zona Rural, Frutal, Minas Gerais, 38200-000, Brazil		
Frutal Bioenergia Ltda.	Ordinary	50.00
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
Praça Gago Coutinho, 540 – Ed. Aeroporto Internacional de Salvador – Box Air BP, city of Salvador, State of Bahia, 41.602-065, Brazil		
Air BP Petrobahia Ltda.	Ordinary	50.00
Praia do Flamengo 66, 13th and 14th floors, Block A, Flamengo, Rio de Janeiro, Brazil		
Gas Natural Acu S.A.	Ordinary	30.00
Rod. BA 827, S/N, KM 05 Estrada do Cantinho dos Aflitos, Fazenda Divino Espirito Santo, City of Barreiras, State of Bahia, 47.819-899, Brazil		
Lightsource Rio Branco Geração de Energia Ltda	Ordinary	49.97
Rodovia Doutor Mendel Steinbruch 10.800, Distrito Industrial, Maracanaú, Ceara, 61.939-906, Brazil		
Ventos De Santa Virginia Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Santo Ubaldo Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Santo Urbano I Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Romualdo Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Teofano Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Teonas Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Thomas Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Tilao Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Vigilio Energias Renovaveis S.A.	Ordinary	50.00
Rodovia GO 410, km 51 à esquerda, Fazenda Canadá, s/n, Zona Rural, Goiás, Edéia, 75940-000, Brazil		
BP Bioenergia Tropical S.A.	Ordinary	50.00
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

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13. Related undertakings of the group – continued

Rodovia SP - 463 Elyeser Montenegro Magalhães, KM 186, S/N, Zona Rural,São Paulo, Ouroeste, 15685-000, Brazil Usina Ouroeste - Açúcar e Álcool Ltda.	Ordinary	50.00
Rodovia TO 010 KM 20, S/N, Zona Rural, Cidade de Pedro Afonso, Tocantins, 77710-000, Brazil Pedro Afonso Bioenergia Ltda.	Ordinary	50.00
Rua do Russel 804, 5th floor, Gloria, Rio de Janeiro, Brazil Gas Natural Acu Comercializadora de Energia Ltda.	Ordinary	50.00
Gas Natural Açú 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	50.00
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 56400-000, Brazil Lightsource Flor Geração de Energia Ltda.	Ordinary	49.97
Cayman Islands		
190 Elgin Avenue, George Town, KY1-9005, Cayman Islands Georgian Pipeline Company	Ordinary	30.37
P.O. Box 309, Ugland House, 113 South Church Street, George Town, Cayman Islands Azerbaijan Gas Supply Company Limited	Ordinary	23.99
Azerbaijan International Operating Company	Ordinary	30.37
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
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
No. B933, 9-14/F Office, Building A, Baoye Center, NO.31 JIA, China Castrol DongFeng Lubricant Co., Ltd	Membership Interest	50.00
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, 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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13. Related undertakings of the group – continued

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 Tensah Petroleum Company "PETROTEMSAH"	Ordinary	25.00
Mediterranean 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
Estonia		
Harju maakond, Lasnamäe linnaosa, Väike-Sõjamäe tn 12a, 11415, Tallinn, Estonia		
Eesti Aviokütuse Teenuste AS	Ordinary	50.00
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 - SOGEP	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
9 Rue Boissy d'Anglas, 75008 Paris, France		
Lightsource France Development SAS	Ordinary	49.97
Germany		
Am Borsigturm 68, Berlin, 13507, Germany		
Service4Charger Holding GmbH	Preference Series A (100.00%)	13.97
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
Brunnenstraße 19-21, Berlin, 10119, Germany		
Digital Charging Solutions GmbH	Membership Interest	33.33

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13. Related undertakings of the group – continued

Godorfer Hauptstraße 186, 50997 Köln, Germany		
Rhein-Main-Rohrleitungstransportgesellschaft mbH	Ordinary	35.00
Jenfelder Allee 80, Hamburg, 22039, Germany		
STDG Strassentransport Dispositions Gesellschaft mbH	Ordinary	50.00
Konsul-Smidt-Strasse 14, 28217 Bremen, Germany		
Etzel-Kavernenbetriebsgesellschaft mbH & Co. KG	Partnership interest	33.33
Etzel-Kavernenbetriebs-Verwaltungsgesellschaft mbH	Ordinary	33.33
Luisenstraße 5 a, 26382 Wilhelmshaven, Germany		
Ammenn GmbH	Ordinary	75.00
Kurt Ammenn GmbH & Co. KG	Partnership interest	50.00
Maximiliansplatz 22, c/o Bird & Bird LLP, 80333, München, Germany		
Lightsource Development Germany GmbH	Ordinary	49.97
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
TGFH Tanklager-Gesellschaft Frankfurt-Hahn GbR		50.00
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
Westfalenamm 166, 44141 Dortmund, Germany		
DOPARK GmbH	Ordinary	25.00
Wittener Straße 45, 44789 Bochum, Germany		
CSG Convenience Service GmbH	Ordinary	24.80
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		
Sun Power 1 S.M.P.C	Other	49.97

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13. Related undertakings of the group – continued

68, Vasilisis Sofias Ave., Athens, 115 28, Greece		
Akarnanika Photovoltaic Systems Single-Member Private Company	Ordinary	49.97
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
Lightsource Renewable Energy Greece Development Single Member S.A.	Ordinary	49.97
Lightsource Renewable Energy Greece Projects Single Member S.A.	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
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 Barat, 11530, Indonesia		
PT. Dirgantara Petroindo Raya	Ordinary	49.90
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
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
Israel		
3 Shenkar Street, Herzelia, Israel		
StoreDot Ltd.	Preference Series C (21.47%)	4.49
Italy		
Via Emilia 1, 20097 San Donato Milanese, Italy		
Azule Energy Angola S.p.A	Membership Interest	50.00
Via Giacomo Leopardi 7, 20123 Milano, Italy		
Belenos s.r.l.	Quotas	32.48
Lightsource Renewable Energy Italy Development, S.r.l.	Quotas	49.97
Lightsource Renewable Energy Italy Finco s.r.l.	Quotas	49.97
Lightsource Renewable Energy Italy Holdings, S.r.l.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 1 s.r.l.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 10 s.r.l.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 11 S.r.l	Quotas	49.97

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13. Related undertakings of the group – continued

Lightsource Renewable Energy Italy SPV 12 S.R.L.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 13 S.R.L.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 14 S.R.L.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 15 S.R.L.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 16 S.R.L.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 2 s.r.l.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 3 s.r.l.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 4 s.r.l.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 6 s.r.l.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 7 s.r.l.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 8 s.r.l.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 9 s.r.l.	Quotas	49.97
Pollon s.r.l.	Quotas	32.48
Via Sardegna, Rome, 38 00187, Italy		
Air BP Italia Spa	Ordinary	50.00
Via Venti Settembre, 69, Palermo, 90141, Italy		
EM Sicilia Green S.r.l.	Quotas	49.97
HF Solar 10 S.r.l.	Quotas	49.97
Marsala Energie S.r.l.	Quotas	49.97
Melilli Energie S.r.l.	Quotas	49.97
ML Energie Rinnovabili S.r.l.	Quotas	49.97
Viale Francesco Scaduto, 2d, Palermo, 90144, Italy		
HF Solar 1 S.r.l.	Quotas	49.97
HF Solar 2 S.r.l.	Quotas	49.97
HF Solar 3 S.r.l.	Quotas	49.97
HF Solar 4 S.r.l.	Quotas	49.97
HF Solar 5 S.r.l.	Quotas	49.97
Japan		
4-2 Otemachi 1-chome, Chiyoda-ku, Tokyo, Japan		
Ishikari Offshore Wind LLC	Ordinary	49.00
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)		
109 Sideung-ro, Hwangsan-myeon, Jeonlanam-do, Korea		
Haenam Solar Power Plant Co., Ltd.	Ordinary	49.97
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
37-23, 517, Yeongdong-daero (Samsung dong, ASEM Tower), Gangnam-gu, Seoul, Republic of Korea, Seoul, Korea (the Republic of)		
LS Renewable Energy Co., Ltd.	Ordinary	49.97
SK Devco Solar Power Plant Co., Ltd.	Ordinary	49.97
3730-23, 37th fl, 517 Yeongdeung-daero, Gangnam-gu, Seoul		
Gangjin Solar Power Plant 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		
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		

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13. Related undertakings of the group – continued

Gezamenlijke Tankdienst Schiphol B.V.	Ordinary	50.00
Basisweg 10, 1043AP Amsterdam, Netherlands		
Lightsource BP Hassan Allam Holdings B.V.	Ordinary	24.99
Butaanweg 215, NL-3196 KC Vondelingenplaat, Rotterdam, Havennummer, 3045, Netherlands		
N.V. Rotterdam-Rijn-Pijpleiding Maatschappij (RRP)	Ordinary	44.40
d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands		
BP Angola (Block 18) B.V.	Ordinary	50.00
Gustav Mahlerplein 28, 1082MA, Amsterdam, Netherlands		
Lightsource Renewable Energy Netherlands Development B.V.	Ordinary	49.97
Lightsource Renewable Energy Netherlands Holdings B.V.	Ordinary	49.97
Zonneuweide Liesveldens B.V.	Ordinary	49.97
Zonneuweide LS 4 B.V.	Ordinary	49.97
Zonneuweide LS 5 B.V.	Ordinary	49.97
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
Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands		
BP AOC Pumpstation Maatschap	Membership Interest	50.00
BP Esso AOC Maatschap	Partnership interest	22.80
BP Esso Pipeline Maatschap	Partnership interest	50.00
Maasvlakte Europoort Pipeline Maatschap	Partnership interest	50.00
Team Terminal B.V.	Ordinary	22.80
Strawinskylaan 1725, 1077XX Amsterdam, Netherlands		
Eni Angola Exploration B.V.	Membership Interest	50.00
Eni Angola Production B.V.	Membership Interest	50.00
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
Corporate Services New Zealand Limited, Level 5, 79 Queen Street, Auckland, 1010, New Zealand		
Lightsource Development Services New Zealand Limited	Ordinary	49.97
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	15.87
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

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13. Related undertakings of the group – continued

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		
Air BP Aramco Poland sp. z o. o.	Ordinary	50.00
ul. Grzybowska 2/29, 00-131, Warszawa, Poland		
Lightsource Development Polska sp. z o.o.	Ordinary	49.97
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 6 sp. z.o.o.	Ordinary	49.97
LS 7 sp. z.o.o.	Ordinary	49.97
LS 8 sp. z.o.o.	Ordinary	49.97
LS 9 sp. z.o.o.	Ordinary	49.97
RD PV Produkcja 5 Spółka Z Ograniczona Odpowiedzialnoscia	Ordinary	49.97
Wena Projekt 2 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 31 de Agosto, nº 12, 5000 - 305 Vila Real, Portugal		
LSBPDG - Sociedade de Produção De Energia, Limitada	Ordinary	24.99
PTSunHydrogen II, LDA	Ordinary	24.99
PTSunHydrogen III, LDA	Ordinary	24.99
PTSunHydrogen IV, LDA	Ordinary	24.99
PTSUNHYDROGEN V, LDA	Ordinary	24.99
Rua Castilho, No 50, 1250-071, Lisboa, Portugal		
Coherent Modernity Lda	Ordinary	49.97
Coloursflow - 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
Lightsource Development Portugal, Unipessoal Lda	Ordinary	49.97
PTSunHydrogen VI, LDA	Ordinary	24.99
PTSunHydrogen VII, LDA	Ordinary	24.99
PTSunHydrogen, LDA	Quotas	24.99
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
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		
Lightsource Renewable Energy Portugal (HoldCo), Lda.	Ordinary	49.97
Romania		
București Sectorul 1, Bulevardul DACIA, Nr. 20, BIROUL NR. HDR20, Etaj 5, Romania		
LIGHTSOURCE DEVELOPMENT ROMANIA S.R.L.	Ordinary	49.97
Otopeni, 59 Aurel Vlaicu Street, Otopeni, Ilfov County, Romania		
Romanian Fuelling Services S.R.L.	Ordinary	50.00
Russian Federation		
629830 Yamalo-Nenetskiy Anatomy Region, city of Gubkinskiy, Russian Federation		
LLC "Kharampurneftegaz"	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

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13. Related undertakings of the group – continued

Limited Liability Company TYNGD	Membership Interest	20.00
Shabolovka street 10 building 2, 7th Floor, Room 13, Municipal District Yakimanka, Moscow, 119049, Russian Federation		
Srednelenskoye Limited Liability Company	Membership Interest	49.00
Saudi Arabia		
Industrial Area Unit No 1, Yanbu Alsenayea, 46481 - 4659, Saudi Arabia		
Arabian Production And Marketing Lubricants Company	Ordinary	50.00
P O Box 6369, Jeddah 21442, Saudi Arabia		
Peninsular Aviation Services Company Limited ^f	Membership Interest	50.00
Singapore		
12 Marina Boulevard, #35-01 MBFC Tower 3, Singapore, 018982, 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
199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, GP, 2196, South Africa		
Masana Petroleum Solutions (Pty) Ltd	Ordinary	37.82
Spain		
Avenida Academia General Militar, 52, Aragón, Zaragoza, 50015, Spain		
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
Calle Alcalá número 63, Madrid, 28014, Spain		
Energía Inagotable de Eolo, S.L.U.	Ordinary	49.97
ISC Greenfield 12, S.L.	Ordinary	49.97
ISC Greenfield 7, 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
Lightsource Renewable Energy Trading, SL	Ordinary	49.97
Modelos Energéticos Sostenibles, S.L.	Ordinary	49.97
Parque FV Borealis, S.L.	Ordinary	49.97
Parque FV Polaris, S.L.	Ordinary	49.97
Calle de la Ribera del Loira, número 60, 28042, Madrid, Spain		
Ateca Renovables, S.L.	Ordinary	24.99
Calle Jose Ortega y Gasset 22-24, 2nd Floor, 28006 Madrid, Spain		
Performan Lark, 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 Paseo de la Castellana 43, 28046, Madrid, Spain		
Almendra Renovables 400KV, S.L.	Ordinary	26.87
Colectora Hiberus-Libienergy, S.L.	Ordinary	24.99
Global Aljarafe, S.L.U	Ordinary	49.97
Global Aroche, S.L.U	Ordinary	49.97
Global Atarazana, S.L.U	Ordinary	49.97
Global Baterno, S.L.U	Ordinary	49.97
Global Baza, S.L.U	Ordinary	49.97

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13. Related undertakings of the group – continued

Global Brenes, S.L.U	Ordinary	49.97
Global Cotolengo, S.L.U	Ordinary	49.97
Global Tarquinia, S.L.U	Ordinary	49.97
Global Treviso, S.L.U	Ordinary	49.97
Global Valdenoches, S.L.U	Ordinary	49.97
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
Campus Empresarial Arbea - Edificio No 1, Carretera Fuencarral a Alcobendas (M-603), km 3.8, 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 Renovables, S.L.	Ordinary	50.00
Pan American Energy, S.L.	Membership Interest	50.00
Carretera de San Andrés/n, La Jurada-María Jiménez, Santa Cruz de Tenerife, Spain		
Terminales Canarias, S.L.	Ordinary	50.00
Paseo de la Castellana 140, 7C, 28046 Madrid, Spain		
Alejandria Power, S.L.U.	Ordinary	49.97
Caletona Servicios y Gestiones, S.L.U.	Ordinary	49.97
Castellana Power, S.L.U.	Ordinary	49.97
Inversiones Energy Madrid, 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 De La Castellana 91 4º 4 Madrid, Spain		
Gómez Narro Renovables 132 kV, A.I.E	Membership Interest	22.72
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		
Malmö Fuelling Services AB	Ordinary	33.33
Box 7, 190 45 Arlanda, Sweden		
Stockholm Fuelling Services Aktiebolag	Ordinary	25.00
Switzerland		
Birmenstorferstrasse 2, Mellingen, 5507, Switzerland		
Tankanlage AG Mellingen	Ordinary	33.33
Lindenstrasse 2, 6340 Baar, Switzerland		
Trans Adriatic Pipeline AG	Ordinary	20.00
Route de Pré-Bois 17, Cointrin, 1216, Switzerland		
Saraco SA	Ordinary	20.00
Zwüschemteich, Rümlang, 8153, Switzerland		
TAR - Tankanlage Ruemlang AG	Ordinary	27.32
Taiwan (Province of China)		
No. 97, 18F, Songren Rd., Xinyi Dist, Taipei City, Taiwan (Province of China)		
Hui-Meng Energy Co., Ltd.	Ordinary	49.97
Lightsource Renewable Energy Development Taiwan Limited	Ordinary	49.97
Lightsource Renewable Energy SPV 1 Taiwan Limited	Ordinary	49.97
Lightsource Renewable Energy SPV 2 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		
Princes Court, Cor. Pembroke & Keate Street, Port-of-Spain, Trinidad and Tobago		

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13. Related undertakings of the group – continued

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
Türkiye		
Degirmen yolu cad. No:28, Asia OfisPark K:3 Icerenkoy-Atasehir, Istanbul, 34752, Türkiye		
ATAS Anadolu Tasfiyehanesi Anonim Sirketi ^b	Ordinary	68.00
Kizilirmak Mahallesi, Ufuk Üniversitesi Caddesi, Fariya Business Center, No. 8, Çukurambar, Çankaya, Ankara, Türkiye		
TANAP Dogalgaz İletim Anonim Sirketi	Ordinary C (100.00%)	12.00
Liman Mah. 60 Sk., Çekisan-İdari Bina sit. No:25 A/1, Konyaalti, Antalya, Türkiye		
Cekisan Depolama Hizmetleri Limited Sirketi	Ordinary	35.00
Yakuplu Mahallesi Genc, Osman Caddesi, No.7 Beylikdüzü, Istanbul, Türkiye		
Ambarli Depolama Hizmetleri Limited Sirketi	Ordinary	50.00
United Arab Emirates		
8th Floor, Standard Chartered Tower, Downtown, Dubai, United Arab Emirates		
Middle East Lubricants Company LLC	Ordinary	29.33
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
United Kingdom		
1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom		
bp Aberdeen Hydrogen Energy Limited	Ordinary B	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	Preference Series A (52.50%); Preference Series A 2 (50.00%)	26.58
2 Chester Row, London, SW1W 9JH, United Kingdom		
Green Biofuels Limited	Ordinary	30.00
29th Floor 40 Bank Street, London, E14 5NR		
Alyssum Group Limited	Membership Interest	26.23
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
5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS, United Kingdom		
British Pipeline Agency Limited	Ordinary	50.00
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 (39.50%)	36.67
713, Cavendish Avenue, Birchwood, Warrington, WA3 6DE, England, United Kingdom		
BiSN Holdings Limited	Preference Series B2 (26.00%)	5.88
7th Floor, 33 Holborn, London, EC1N 2HU, England, United Kingdom		
Aashman Power Limited	Ordinary	49.97
Bodmin Solar Limited	Ordinary	49.97
Burnthouse Solar Limited	Ordinary	49.97

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13. Related undertakings of the group – continued

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 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
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) Limited	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
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 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

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13. Related undertakings of the group – continued

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 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
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 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 Greece Holdings 2 (UK) Limited	Ordinary	49.97
Lightsource Renewable Energy Greece Projects 2 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 New Zealand 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 (PPA) Limited	Ordinary	49.97
Lightsource Residential Rooftops Limited	Ordinary	49.97

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13. Related undertakings of the group – continued

Lightsource Simba Limited	Ordinary	49.97
Lightsource SPV 10 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
Lightsource SPV 151 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 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 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 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 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

The parent company financial statements of BP p.l.c. on pages 291-349 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

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 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 288 Limited	Ordinary	49.97
Lightsource SPV 29 Limited	Ordinary	49.97
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 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 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	49.97
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

The parent company financial statements of BP p.l.c. on pages 291-349 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

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
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. 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, England, United Kingdom		
Angola JVCO Limited	Ordinary	50.00
BP Exploration (Angola) Limited	Ordinary	50.00
BP Exploration Angola (Kwanza Benguela) Limited	Ordinary	50.00
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
Morven Offshore Wind Holdings Limited	Ordinary	50.00
Morven Offshore Wind Limited	Ordinary	50.00
Eni House, 10 Ebury Bridge Road, London, SW1W 8PZ, United Kingdom		
Azule Energy Holdings Limited	Ordinary	50.00
Solenova Limited	Ordinary	25.00
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		
Helix Power Limited	Membership Interest	32.40
Mclaren Building Suite, 14a McLaren Building, 46 Priory Queensway, Birmingham, B4 7LR, United Kingdom		
Grid Edge Limited	Preferred Series A (60.00%); Preferred Series A 2 (58.68%)	22.15
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
Redruth House, Cornwall Business Park, West Scorrier, Cornwall, TR16 5EZ		
Wick Farm Grid Limited	Ordinary	24.99
Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom		

The parent company financial statements of BP p.l.c. on pages 291-349 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Lightsource Renewable Energy (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 (Liquidated)	Membership Interest	40.00
The Consolidated Petroleum Company Limited	Ordinary B	50.00
The Consolidated Petroleum Supply Company Limited ⁹	Ordinary	50.00
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
Windsor House, Cornwall Road, Harrogate, England, HG1 2PW, United Kingdom		
C-Capture Limited	Preference Series A (25.31%)	17.51
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.	Membership Interest	37.50
BP-Husky Refining LLC	Membership Interest	50.00
Caesar Oil Pipeline Company, LLC	Membership Interest	56.00
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
CE bp Renew Dynamic Co III, LLC	Membership Interest	40.00
Cedar Creek II Holdings LLC	Membership Interest	50.00
Chicap Pipe Line Company	Ordinary	28.65
Cleopatra Gas Gathering Company, LLC	Membership Interest	53.00
Drumgoon Digester Renewable Energy, LLC	Membership Interest	40.00
East Valley Development, LLC	Membership Interest	50.00
Endymion Oil Pipeline Company, LLC	Membership Interest	65.00
Fowler II Holdings LLC	Membership Interest	50.00
Fowler Ridge II Wind Farm LLC	Membership Interest	50.00
Goshen Phase II LLC	Membership Interest	50.00
KM Phoenix Holdings LLC	Membership Interest	25.00
Mars Oil Pipeline Company LLC	Partnership interest	28.50
Marshall Ridge Renewable Energy, LLC	Membership Interest	40.00
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	65.00

The parent company financial statements of BP p.l.c. on pages 291-349 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Tri-Cross Renewable Energy, LLC	Membership Interest	47.50
Ursa Oil Pipeline Company LLC	Membership Interest	22.69
Van Winkle Digester Renewable Energy, LLC	Membership Interest	47.50
VF Renewable Energy, LLC	Membership Interest	40.00
WMR Renewable Energy, LLC	Membership Interest	50.00
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.	Membership Interest	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		
Szyzygy Plasmonic Inc.	Preference	50.00
251 Little Falls Drive, Wilmington, DE 19808, United States		
Apis Innovation Inc.	Ordinary	35.00
Atlas RNG LLC	Membership Interest	50.00
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	Class B 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
Big Elk Solar, LLC	Membership Interest	49.97
Bighorn Solar 1, LLC	Membership Interest	49.97
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
Bighorn Solar Holdings 2, LLC	Membership Interest	49.97
Bighorn Solar Holdings, LLC	Class B Membership Interest	49.97
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
Cardinal Solar Class B, LLC	Membership Interest	49.97
Cardinal Solar Construction Holdings, LLC	Membership Interest	49.97
Cardinal Solar Construction, LLC	Membership Interest	49.97
Cardinal Solar Holdings 1, LLC	Membership Interest	49.97
Cardinal Solar Holdings 2, LLC	Membership Interest	49.97
Cardinal Solar Holdings, LLC	Membership Interest	49.97
Champion 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 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

The parent company financial statements of BP p.l.c. on pages 291-349 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

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
Crossvine Solar 1, LLC	Membership Interest	49.97
Driver Solar Holdings, LLC	Membership Interest	49.97
Driver Solar, LLC	Membership Interest	49.97
Eden RNG LLC	Membership Interest	50.00
Elk Hill Solar 1 Holdings, LLC	Membership Interest	49.97
Elk Hill Solar 1 Storage, 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	Class B Membership Interest	49.97
Glade Solar Land Holdings, LLC	Membership Interest	49.97
Granite Hill Solar Land Holdings, LLC	Membership Interest	49.97
Granite Hill Solar, LLC	Membership Interest	49.97
Green Meadows RNG LLC	Membership Interest	50.00
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
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	Class B Membership Interest	49.97
Inverness Solar, LLC	Membership Interest	49.97
Janus RNG LLC	Membership Interest	50.00
Johnson Corner Solar I, LLC	Membership Interest	49.97
Jones City Solar II, LLC	Membership Interest	49.97
Jones City Solar, LLC	Membership Interest	49.97
Kirkham Solar Farms I, LLC	Membership Interest	49.97
Kirkham Solar Farms II, LLC	Membership Interest	49.97
Lightsource Beacon 2, LLC	Membership Interest	49.97
Lightsource Beacon 3, 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

The parent company financial statements of BP p.l.c. on pages 291-349 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

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 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 Services Holdings, LLC	Membership Interest	49.97
Lightsource Renewable Energy Services, Inc.	Ordinary	49.97
Lightsource Renewable Energy Trading, LLC	Membership Interest	49.97
Lightsource Renewable Energy US, LLC	Membership Interest	49.97
LSBP NE Development, 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	Class B Membership Interest	49.97
Mayapple Solar Holdings 1, LLC	Membership Interest	49.97
Mayapple Solar Holdings, LLC	Membership Interest	49.97
Mayapple Solar, LLC	Membership Interest	49.97
Oxbow Solar Farm 1, LLC	Membership Interest	49.97
Oxbow Solar Land Holdings, LLC	Membership Interest	49.97
Pacific Offshore Wind Holdings LLC	Membership Interest	50.00
Pacific Offshore Wind LLC	Membership Interest	50.00
Pan RNG LLC	Membership Interest	50.00
Paper Shell Solar 1, LLC	Membership Interest	49.97
Peony Solar 1, LLC	Membership Interest	49.97
Pine Burr Solar 1, LLC	Membership Interest	49.97
Pine Cone Solar 2, LLC	Membership Interest	49.97
Pine Cone Solar 3, LLC	Membership Interest	49.97
Pine Cone Solar, LLC	Membership Interest	49.97
Poplar Solar 1, LLC	Membership Interest	49.97
Prairie Ronde Solar Farm, LLC	Membership Interest	49.97
Red Dusk Solar 1, LLC	Membership Interest	49.97
Renewable Energy Shared Assets LLC	Membership Interest	50.00
Saturn Renewables LLC	Membership Interest	50.00
Shorebird Solar, LLC	Membership Interest	49.97
Snowdrop Solar, LLC	Membership Interest	49.97
Starr Solar Ranch 1, LLC	Membership Interest	49.97
Starr Solar Ranch LLC	Membership Interest	49.97
Sun Mountain Solar 1, LLC	Membership Interest	49.97
Sycamore Trail Solar, LLC	Membership Interest	49.97
Titan Partners LLC	Membership Interest	25.00
Trinity River Solar 1, LLC	Membership Interest	49.97
TX Gulf Solar 1, 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
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		

The parent company financial statements of BP p.l.c. on pages 291-349 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Cantera K-3 Limited Partnership	Partnership interest	39.00
8 the Green, Ste A, Dover, Kent, DE, 19901		
Lutum Technology LLC	Membership Interest	20.00
815, 14th Street SW, Suite A100, Loveland, CO 80537, United States		
Lightning eMotors, Inc.	Ordinary	25.51
850 New Burton Road, Suite 201, Dover, Delaware, 19902, United States		
SeaPort Midstream Partners, LLC	Membership Interest	49.00
Zippity, Inc.	Membership Interest	22.60
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
9900 Spectrum Drive, Austin, TX 78717		
Austin Elements Inc.	Ordinary	30.00
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
FERMULY 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
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 Tendeseke Office Park, Samora Machel Av/Renfrew Road, Harare, Zimbabwe		
Central African Petroleum Refineries (Pvt) Ltd	Membership Interest	20.75

^a 100% interest held directly by BP p.l.c.

^b 15% interest held directly by BP p.l.c.

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

^d 0.01% interest held directly by BP p.l.c.

^e 99% interest held directly by BP p.l.c.

^f 50% interest held directly by BP p.l.c.

^g 5% interest held directly by BP p.l.c.