bp Annual Report and Form 20-F 2024

Growing shareholder value

We are fundamentally resetting bp's strategy. We are reallocating capital to drive growth from our highest returning businesses. And we are focused on driving improved performance.

This is all in service of growing long-term shareholder value.

We believe bp has a compelling investor proposition, sustainably delivering long-term shareholder value through the energy transition, see **page 19**.

Our reset strategy

We plan to grow the upstream, focus the downstream and invest with discipline in transition, see **page 8**.

Navigating this report

Read more on another page of this report

Read more online

Task Force on Climate-related Financial Disclosures (TCFD)
Information that supports TCFD Recommendations and Recommended Disclosures in relation to Metrics and Targets is indicated with TCFD.

Glossary
Words and terms marked with ★ are defined in the glossary on **page 351**

More information

Online quick read
A concise summary of the *bp Annual Report and Form 20-F 2024*, highlighting strategy, performance and sustainability information.

bp.com/annualreport

Online reporting centre
All our bp corporate reports, including the *bp Sustainability Report* and the *bp Energy Outlook*.

bp.com/reportingcentre

2024 at a glance

As at 31 December 2024

Scale

100,500[a]
employees
(2023 87,800)

61
countries of operation
(2023 61)

2.4
million barrels of oil equivalent – upstream★ production
(2023 2.3mmboe/d)

>39,000
electric vehicle charge points★
(2023 >29,000)

21,200
retail sites★
(2023 21,100)

Performance

$0.4bn
profit for the year attributable to bp shareholders
(2023 $15.2bn)

$8.9bn ●
underlying replacement cost (RC) profit★
(2023 $13.8bn)

95.2% ●
bp-operated upstream plant reliability★
(2023 95.0%)

94.3% ●
bp-operated refining availability★
(2023 96.1%)

2,950
strategic convenience sites★
(2023 2,850)

8.2GW
developed renewables to FID★ (net)
(2023 6.2GW)

$6.17/boe ●
upstream unit production costs★
(2023 $5.78/boe)

Safety and sustainability

38 ●
tier 1 and 2 process safety events★
(2023 39)

33.6MtCO_2e ●
GHG emissions – operational control
(2023 32.1MtCO_2e)

Key

● Key performance indicator, **page 14**

a This figure reflects new acquisitions and companies we have taken full ownership of including bp bioenergy and Lightsource bp.

★ See glossary on **page 351**

About bp

We are an integrated energy company, one of only a few that can deliver energy at global scale through a decades-long energy transition.

We are in action to grow shareholder value, strengthen bp and build our resilience to deliver energy to the world, today and tomorrow.

We have operations in Europe, North and South America, Australasia, Asia and Africa.

Our purpose

Our purpose is to deliver energy to the world, today and tomorrow.

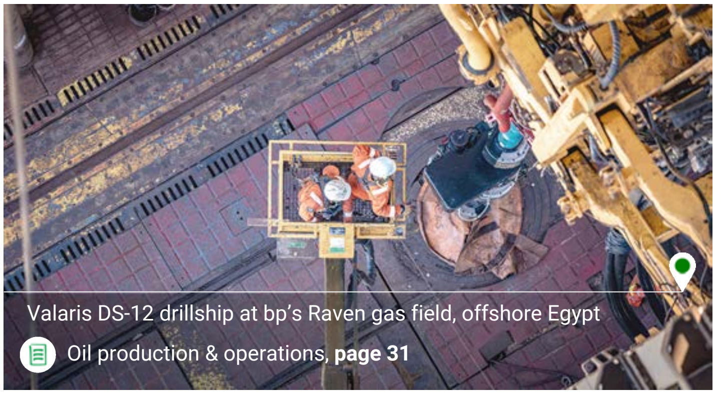
Who we are

'Who we are' defines what we stand for at bp, building on our best qualities and those things that are most important to us. It comprises three simple beliefs that can inspire each of us at bp to be our best every day: live our purpose, play to win, care for others.

bp.com/ourbeliefs

Block 61 Khazzan gas field in Oman

Gas & low carbon energy, **page 28**



Valaris DS-12 drillship at bp's Raven gas field, offshore Egypt

Oil production & operations, **page 31**

Financial reporting segment performance

At 31 December 2024, the group's reportable segments were gas & low carbon energy, oil production & operations and customers & products. Each is managed separately, with decisions taken for the segment as a whole, and represents a single operating segment that does not result from aggregating two or more segments (see Financial statements – **Note 5**).

Gas & low carbon energy[a]

Comprises our gas & low carbon energy businesses. Our gas business includes regions with upstream activities that predominantly produce natural gas, integrated gas and power, and gas trading. Our low carbon business includes solar, offshore and onshore wind, hydrogen and carbon capture and storage (CCS), and power trading. Power trading includes trading of both renewable and non-renewable power.

$3.6bn

replacement cost (RC) profit before interest and tax[b]
(2023 $14.1bn)

$6.8bn

underlying RC profit before interest and tax★
(2023 $8.7bn)

Segment performance, **page 28**

Oil production & operations[a]

Comprises regions with upstream activities that predominantly produce crude oil, including bpx energy.

$10.8bn

RC profit before interest and tax[b]
(2023 $11.2bn)

$11.9bn

underlying RC profit before interest and tax
(2023 $12.8bn)

Segment performance, **page 31**

Customers & products

Comprises customer-focused businesses, which include 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[c] businesses.

$(1.6)bn

RC loss before interest and tax[b]
(2023 profit $4.2bn)

$2.5bn

underlying RC profit before interest and tax
(2023 $6.4bn)

Segment performance, **page 33**

Other businesses & corporate

Comprises technology; bp ventures; our corporate activities and functions; and any residual costs of the Gulf of America oil spill.

$(1.0)bn

RC loss before interest and tax[b]
(2023 loss $(0.9)bn)

$(0.6)bn

underlying RC loss before interest and tax
(2023 loss $(0.9)bn)

Segment performance, **page 36**

The *Gigahub* EV charging hub at the NEC in Birmingham, UK

Customers & products, **page 33**

bp's Xazar Centre office in Baku, Azerbaijan

Other businesses & corporate, **page 36**

a The Azerbaijan-Georgia-Türkiye and Middle East regions have been further subdivided by asset.
b IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker. For bp, this measure of profit or loss is replacement cost profit before interest and tax, which reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses★ from profit before interest and tax. Replacement cost profit for the group is not a recognized measure under IFRS. For further information see Financial statements – Note 5.
c In February 2025 bp announced its intention to move its biogas business to the gas & low carbon energy segment.

★ See glossary on **page 351**

Chair's letter

Dear fellow shareholders,

Chief executive transition

The world bp operates in continues to change at pace. The past year has seen numerous elections, complex geopolitics and ongoing conflict, as well as significant climate events. At the same time, there has been progress in AI and technology and some signs of growth and prosperity in emerging economies. As a result, energy demand continues to rise with the supply of oil and gas, and renewable energy, reaching an all-time high.

For bp, there was leadership change, with a new CEO and CFO, and 2024 was a year of reshaping the portfolio and laying the foundation for growth and sustainable shareholder returns. Under Murray Auchincloss's leadership, bp has made significant moves, continuing to play its part in supplying the energy the world needs today and helping build out the energy system of tomorrow. We strengthened our oil and gas portfolio, expanded in biogas and bioenergy, and focused our hydrogen and wind projects – all leading to the fundamental strategy reset announced at our Capital Markets Update in February 2025.

Performance

Safety continues to be at the forefront of everything bp does, and the board and I would again like to recognize bp's teams for their work to reduce the most serious process safety incidents. This requires constant vigilance, robust processes and a willingness to speak up and act.

However, whether it is on the front line or on the board, bp can never take safety for granted. We were tragically reminded of this in October 2024 by the fatality in our bp bioenergy business in Brazil.

Many of bp's businesses performed well, including higher upstream★ production and strong plant reliability★, but it was a difficult year in parts of our customers & products business, particularly in refining. bp cannot control a tough price environment but it can address underlying performance – and the board believes that the comprehensive update of our strategy that we announced in February, combined with strong performance management processes, will help bp to do this.

Strategy reset

A lot has changed since we launched our strategy in 2020 – and bp has learned a lot. The pandemic has altered consumer behaviour, geopolitical tensions have increased the focus on security of supply, and although energy demand has risen to a high point, overall, growth has been weaker. Globally, inflation and rising interest rates have had an impact on the economics of major projects, particularly low carbon investments.

Because of all these factors, combined with our engagement with our shareholders and other important stakeholders, we reworked our strategy. Murray sets out how on the next page.

This is a new direction for bp. The board has worked closely with Murray and his leadership team throughout this reset, which has our full support. The reset builds on bp's distinctive strengths, learns from its challenges and represents deliberate choices and a conviction about the way forward. The next steps are clear. Now is about rigorous performance, and the board has an important role to play in overseeing the delivery of the strategy we have set out.

Culture and values

The board believes that the changes bp is making are positive and necessary for the future of the company, but we know change itself can be unsettling. This makes it more crucial than ever that bp maintains a strong culture and strong values. bp is rigorous about operational and safety processes, and must continue to be rigorous about care for others, our speak-up culture and psychological safety. As a board, we provide oversight and constructive challenge, and in doing so we routinely monitor bp's culture. I say more about this in the governance section on **page 70**.

Closing thanks

Thank you, particularly to bp's owners and bp's teams, in a year where bp has faced numerous challenges and worked hard to improve its performance and focus the organization. We are grateful to everyone who has given us their time, expertise, support – and challenged us too. This is your company and we believe it is now set to grow – and win – in a changing energy market.

Helge Lund
Chair
6 March 2025

Chief executive officer's letter

Dear fellow shareholders,

We've been in action throughout the past year materially reshaping bp's portfolio and laying the foundations for February's Capital Markets Update. This fundamental reset of our strategy demonstrates a clear focus on actions to drive performance improvement and grow cash flow and returns for bp's shareholders.

Safety first

In 2024, we made progress on safety, reducing the number of combined tier 1 and 2 process safety events★ for a second year in a row, with the most serious tier 1 events down significantly – but we have more to do. Our goal is to eliminate fatalities, life-changing injuries and the most serious process safety incidents. Tragically, one person died while working in our newly acquired bp bioenergy business in Brazil in October 2024. We must continue to embed and reinforce our Operating Management System★, Lifesaving Rules and Safety Leadership Principles across bp (see **page 56**). Nothing matters more than safety.

Financial and operating performance

We delivered strong performance in some areas in 2024 but had some challenges in others. For example, our upstream★ production was 2% higher than in 2023, and plant reliability★ was strong at over 95%, but there were difficulties in refining. Margins were lower and the power outage at Whiting in the first quarter contributed to a dip to 94.3% in our refining availability★.

This contributed to earnings of $38 billion[a] (adjusted EBITDA★) in 2024 and operating cash flow★ of $27.3 billion and resulted in:

- Profit for the year attributable to shareholders of $0.4 billion.
- Underlying replacement cost profit★ of $8.9 billion.
- Return on average capital employed★ of 14.2%[b].
- And net debt★ of $23 billion[c].

This allowed us to raise the dividend per ordinary share by 10% and announce $7 billion of share buybacks for the year.

Reshaping the portfolio

We've done more to reshape bp's portfolio in the last 12 months than in any year in the past 20 years. We started up a major project★ and sanctioned 10. We agreed new access in regions we know well, including in Iraq and India – at material scale. We formed a new joint venture, Arcius Energy, to develop gas in the Middle East with ADNOC's investment arm XRG. And we announced plans for JERA Nex bp, joining forces with one of the world's major power companies to create a leader in offshore wind development – and helping to grow the scale of the business in a capital-light way for bp. We also now own 100% of bp bioenergy, one of the top-three sugarcane bioethanol producers in Brazil, and Lightsource bp, one of the world's leading solar developers. And we're investing with discipline in hydrogen and carbon capture, sanctioning four projects in 2024.

At the same time, we introduced our target to deliver at least $2 billion of savings[d] by the end of 2026, relative to 2023. We made strong progress on this, achieving structural cost reduction★ of $0.8 billion since the start of 2024.

Growing shareholder value

Having laid the foundations, we have fundamentally reset our strategy. This is a new direction. We've drawn on everything we've learned since 2020, while reflecting substantial changes to the external environment and using our deep-seated industrial skills and experience. The key elements are:

- First, a growing upstream. We're increasing planned investment by 20% to around $10 billion a year in oil and gas to help build more higher-returning major projects and increase exploration.
- Second, a focused downstream. We're focusing our portfolio around core integrated positions and taking action to improve performance. We expect to invest around $3 billion by 2027.
- Third, investing with discipline in the transition. We plan to pursue fewer and higher-returning opportunities, and access growth more efficiently. We now expect to invest between $1.5-2.0 billion per year into transition businesses★ through 2027[e] – more than $5 billion lower per year than our previous guidance.

All while continuing to drive value through our distinctive strengths in trading, technology and partnerships. And we are now guided by a more focused set of sustainability aims, the ones most relevant to our net zero ambition and the long-term success of bp (see **page 38**).

Thank you

There are very few companies of scale that can adapt at pace with society to meet demand from countries, companies and customers for more energy and lower carbon products. bp is one of them. I'm excited about our new direction and the significant opportunity we have to grow value for our shareholders.

I want to thank our brilliant team for their hard work, commitment and resilience through a period of extensive change. I also want to thank you, the owners of our business, for continuing to put your trust in our company.

Murray Auchincloss
Chief executive officer
6 March 2025

Nearest IFRS-equivalent measures

$1.2bn

profit for 2024[a]

0.5%

profit for 2024 attributable to bp shareholders divided by total equity at 31 December 2024[b]

$59.5bn

finance debt at the end of 2024[c]

a Adjusted EBITDA for the group is a non-IFRS measure and its nearest IFRS-equivalent measure is profit for the year 2024.
b ROACE is a non-IFRS measure and its nearest IFRS measures of numerator and denominator are profit for 2024 attributable to bp shareholders of $0.4 billion and total equity at the end of 2024 of $78.3 billion respectively.
c Net debt is a non-IFRS measure and its nearest IFRS-equivalent measure is finance debt at the end of 2024.
d Target first introduced in bp's first quarter 2024 group results announcement referred to as cash costs savings. Cash costs has the same meaning as underlying operating expenditure★.
e Excludes deferred consideration for 2024 acquisition of bp bioenergy in 2025.

★ See glossary on **page 351**

The operating environment

bp operates across volatile energy markets. Here we discuss broader economic trends we have observed that influence our sector as a whole.

The world economy grew by around 3%[a] in 2024. Growth rates varied widely across economies, with US GDP estimated to have grown by 2.8%[a], much stronger than had been expected at the start of the year[b]. By contrast, the eurozone economy expanded by only 0.8%[a]. China's growth is estimated to have been close to the government's 'around 5%' target[a].

Inflation continued to moderate around the world in 2024, moving towards central banks' target rates in most major economies. Cooling inflation allowed several central banks, including the US Federal Reserve, the European Central Bank and the Bank of England, to cut interest rates. Financial market prices suggest further interest rate reductions are expected during 2025.

Oil

Oil prices were elevated across much of 2024, supported by oil demand growth and OPEC production cuts. Dated Brent averaged $81/bbl[c] in 2024, broadly unchanged from $83/bbl[c] in 2023. A slowdown in Chinese oil demand growth to a quarter of its pre-COVID trend lowered global annual oil demand growth to 0.94mmb/d, causing total oil demand in 2024 to be 102.9mmb/d[d].

The slowdown in demand growth and outperformance of non-OPEC+ supply led to production cuts from OPEC+ in 2024. OPEC+ output averaged 49.8mmb/d in 2024 – around 900kb/d[d] lower than 2023. Saudi Arabia cut its output to just 9.0mmb/d in 2024, over 1mmb/d lower than its levels in the first half of 2023[d]. These reductions were more than offset by strong growth in non-OPEC+ supplies which increased by 1.5mmb/d in 2024[d], with the US accounting for almost half of that increase[d].

Natural gas

A relatively warm European winter in 2023-24 and muted European gas demand caused European and Asian natural gas prices to fall in early 2024. Prices troughed in February but had increased by 70%[e] by the end of December following strong Asian LNG demand growth and weak LNG supply growth.

Industry, power generation and transportation were the main sectoral drivers of that Asian LNG demand growth. European gas demand continued to decline due to lower power demand. Outages and project delays meant global LNG supply grew at a slow pace of 2.5% in 2024[f].

In the US, Henry Hub (HH) gas prices averaged $2.2/mmBtu[g], the lowest price level, in real terms, in the last 25 years. A warm US winter (2023-24) resulted in natural gas stocks 40%[h] above the five-year average by the end of March. Consequently, HH declined to levels needed to incentivize power sector coal-to-gas switching and lower natural gas production. Increases in power demand for air conditioning and data centres aided this rebalancing. The number of US gas rigs in key shale basins declined by 47% from its peak in 2022[i].

Refining marker margin

We use a global refining marker margin (RMM)★ to track the refining margin environment. Global RMM in 2024 continued the downward trajectory from 2023. An increase in refining capacity and a slowdown in demand growth for refined products meant RMM values averaged significantly lower in 2024 at $17.7/bbl ($8.1/bbl lower than in 2023)[j].

Power and renewables

Electricity demand growth continues to outpace total energy demand growth, driven by increasing electrification in developed economies and by growing prosperity and industrialization in emerging economies. Growing demand from data centres looks set to increase electricity demand materially in the coming years.

Total solar and wind capacity additions in 2024 are estimated to have exceeded 600GW, breaking the record set in 2023[k]. This surge was associated with significant overcapacity in solar manufacturing in China.

Bioenergy growth also maintained momentum, with resilient demand for liquid biofuels in road transport, increasing biomethane production, and increasing announced capacity of sustainable aviation fuel projects.

Hydrogen and carbon capture and storage

Persistent high costs, the slow pace of enabling policy and insufficient demand continue to challenge the decarbonization of costlier-to-abate processes with low carbon hydrogen. The project pipeline for production of low carbon hydrogen operational by 2030 remains significant, but only around 4Mtpa[l] is either currently operational or under construction. Green hydrogen★ costs are expected to be higher than those for blue hydrogen★ in many countries through this decade and beyond.

Carbon capture and storage (CCS) is increasingly being recognized as critical to the energy transition, and the global pipeline of CCS projects continued to grow in 2024. Operational and under-construction projects are expected to double to 100Mtpa[m] over the next few years. While this represents progress, the current project pipeline, taking into account relatively low historical success rates, appears insufficient to meet the CCS deployment rates in Paris-consistent transition scenarios[n].

Market activity	2024	2023
Global oil consumption[d]	**102.9mmb/d**	102.0mmb/d[q]
Global oil production[d]	**102.9mmb/d**	102.3mmb/d[q]
Natural gas consumption[f]	**4,212bcm**	4,097bcm[r]
Natural gas production[f]	**4,190bcm**	4,134bcm[r]
Dated Brent average[c]	**$80.76/bbl**	$82.64/bbl
West Texas Intermediate (WTI)★ average[o]	**$75.87/bbl**	$77.67/bbl
Henry Hub average[g]	**$2.19/mmBtu**	$2.53/mmBtu
Dutch Title Transfer Facility (TTF)★ average[e]	**34.4 euros per MWh ($10.9/mmBtu)**	40.5 euros per MWh ($12.8/mmBtu)
Japan-Korea (Asian) LNG average[p]	**$11.9/mmBtu**	$13.8/mmBtu
Refining marker margin[j]	**$17.7/bbl**	$25.8/bbl

a IMF World Economic Outlook, October 2024, measured on a Purchasing Power Parity basis.
b IMF World Economic Outlook Update, January 2024.
c Refinitiv Data Service (Dated Brent spot price).
d IEA Oil Market Report, January 2025.
e Platts Dutch TTF Day Ahead price.
f IEA Gas Market Report, Q1 2025.
g Platts Henry Hub cash price.
h Weekly Natural Gas Storage Report, EIA.
i EIA Short Term Energy Outlook, Appalachia and Haynesville regions.
j The RMM may not be representative of the margin achieved by bp in any period because of bp's particular refinery configurations and crude and product slates. In addition, the RMM does not include estimates of energy or other variable costs.
k *bp Energy Outlook 2024*; IRENA Stats; Wood Mackenzie Global Solar Forecasts. PV capacity additions are converted from DC to AC basis by dividing by ~1.2.
l WoodMac Lens; Hydrogen Project Pipeline data, October 2024.
m WoodMac Lens; CCUS Project Pipeline data, October 2024.
n Projects include capture projects either on a standalone basis or as part of a hub (sharing transport and storage facilities).
o Refinitiv Data Service (West Texas Intermediate).
p Platts JKM spot price.
q This number is restated from the *bp Annual Report and Form 20-F 2023* to reflect revisions made in the IEA Oil Market Report, January 2025.
r This number is restated from the *bp Annual Report and Form 20-F 2023* to reflect revisions made in the IEA Gas Market Report, Q1 2025.

Energy outlook

The *bp Energy Outlook 2024 (2024 Outlook)* explores the trends and uncertainties surrounding the energy transition out to 2050.

The bp Energy Outlook helps inform bp's core beliefs about the energy transition. The scenarios within it explore the possible implications of different judgements and assumptions concerning the nature of the energy transition. The uncertainty associated with the transition is substantial, and these scenarios are not predictions of what is likely to happen or what bp would like to see happen. We use the output from these scenarios to inform our strategic thinking.

We published the *2024 Outlook* in July 2024, designed around two scenarios informed by recent trends and developments in the global energy system. The *2024 Outlook* provides key insights about how the energy system may evolve over the next 25 years.

The two scenarios – Current Trajectory and Net Zero (see 'Two scenarios to explore the energy transition', below) – explore the speed and shape of the energy transition out to 2050 and help to shape a resilient strategy for bp.

Read the *bp Energy Outlook 2024*
bp.com/energyoutlook

A new theme discussed throughout the *2024 Outlook* centres on the challenge of moving from the current 'energy addition' phase of the energy transition to an 'energy substitution' phase. In this second phase, low carbon energy increases sufficiently quickly to more than match increases in global energy demand, allowing the consumption of fossil fuels, and their associated emissions, to decline.

Scenarios for strategic decision making

We use scenarios to inform strategy, manage risk, and improve decision making.

Some of the scenarios are based on climate and other policies currently in force, and on current global aims and pledges around the energy transition. Other scenarios are based on achieving a certain pace or degree of transition, and consider how the energy system might change to achieve that.

In thinking about appropriate scenarios to inform our strategy, we used both approaches.

How scenarios inform our strategy

The use of scenarios described in the *2024 Outlook*, and those from other organizations, aids our understanding of the energy transition and helps us to think about how different outcomes might impact our strategy.

The use of a broad range of scenarios to inform our strategy supports our efforts to make it robust and resilient to the range of uncertainty we face.

By considering various time horizons we can identify key milestones or signposts which might emerge over the next five, 10 or 25 years and inform our view of the key sources of uncertainty affecting the global energy system.

We actively monitor for changes in the external environment and refresh or review the scenarios as needed in response to these signals.

For the purposes of testing the resilience of our strategy to the range of uncertainty in the energy transition, we have used scenarios drawn from other credible sources such as the UN Principles for Responsible Investment (UN PRI) and the International Energy Agency (IEA). Read more on our resilience analysis and the outcome of that work on **page 50**.

How we create scenarios

We quantify a range of scenarios in the *2024 Outlook* using our global energy modelling system. This comprises a suite of models to help us understand the supply and demand dynamics of the global energy system.

The modelling framework uses historical data based on the Energy Institute's Statistical Review of World Energy, the IEA's World Energy Balances data and a range of other data sets.

Each scenario is determined by a set of key assumptions, including population and economic growth, pace of technological change, resource constraints and government policies. These are informed by expert analysis from external organizations including the United Nations, Oxford Economics and Rystad Energy. We benchmark our scenarios against external organizations including the IEA, the IPCC, and S&P Global.

The modelling techniques used vary by sector and include a combination of econometric modelling, adoption curves and consumer choice modelling.

Two scenarios to explore the energy transition

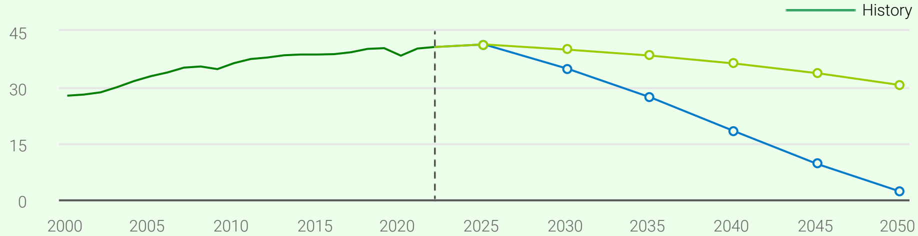
Carbon emissions Gt of CO_2e[a]

Current Trajectory

is designed to capture the broad pathway along which the global energy system is currently travelling. It places weight on climate policies already in force and on global aims and pledges for future decarbonization. At the same time, it also recognizes the myriad challenges associated with meeting these aims. CO_2 equivalent (CO_2e) emissions in Current Trajectory peak in the mid-2020s and by 2050 are around 25% below 2022 levels.

Net Zero

explores how different elements of the energy system might change to achieve a substantial reduction in carbon emissions. In that sense, Net Zero can be viewed as a 'what if' scenario: what elements of the energy system might change, and how, if the world collectively acts for CO_2e emissions to fall by around 95% by 2050.



a Carbon emissions include CO_2 emissions from energy use, industrial processes, natural gas flaring and methane emissions from energy production.

Resetting strategy

Growing upstream

Focusing downstream

Disciplined investment in transition

Growing the upstream: our oil and gas business

We plan to increase investment to grow production while also growing cash flow, in addition to disciplined expansion of biogas. Maintaining strong and safe operations throughout.

Focusing the downstream: our customers and products business

We are reshaping the portfolio to focus on markets and businesses where we have advantaged and integrated positions. We have clear actions to drive improved performance, including addressing costs in our customers business, and improving operations in refining.

Investing with discipline in transition

We plan to invest with discipline: with selective investment in biogas, biofuels and EV charging, where we see strong demand growth; adopting innovative capital-light partnerships in renewables; and focusing investment on hydrogen and carbon capture projects to support us in decarbonizing our operations, and position us for growth through the next decade. We now expect capital investment into transition businesses★ to be between $1.5-2.0 billion per year through 2027[a] – more than $5 billion lower per year than our previous guidance.

All while continuing to drive value through our distinctive strengths in trading, technology and partnerships.

Our primary targets

We have set out four primary targets that we will use to measure our progress and how we are improving performance. These targets, alongside the guidance and financial frame (see **page 18**), support our reset. Taken together, we believe our primary targets will underpin growth in the value of bp.

Adjusted free cash flow★ growth

>20%[b]

adjusted free cash flow compound annual growth rate (CAGR)★ from 2024-27

Net debt★

$14-18bn[c]

by end 2027

Structural cost reduction★

$4-5bn

by end 2027

Return on average capital employed (ROACE)★

>16%[b]

in 2027

a Excludes deferred consideration for 2024 acquisition of bp bioenergy in 2025.
b At $70/bbl Brent, $4/mmBtu Henry Hub, and $17/bbl refining marker margin, all 2024 real.
c Potential proceeds from any transactions related to *Castrol* strategic review and announcement to bring a strategic partner into Lightsource bp will be allocated to reduce net debt.

2024 performance

On 26 February 2025 we announced a new strategy and retired our previous strategic pillars, together with the associated strategic targets and aims.

To help stakeholders understand progress against our previous strategy in 2024, we have included the following metrics reported under the previous strategy for the year ended 31 December here[a]. From 2025, we will report annually on our progress delivering the primary metrics shown on **page 8**.

Metrics TCFD	2024	2023
Upstream★ production	**2.4mmboe/d**	2.3mmboe/d
bp-operated upstream plant reliability★	**95.2%**	95.0%
Upstream unit production costs★	**$6.17/boe**	$5.78/boe
bp-operated refining availability★	**94.3%**	96.1%
Biofuels production★	**35kb/d**	32kb/d
Biogas supply volumes★[b]	**23mboe/d**	22mboe/d
LNG portfolio★	**23Mtpa**	23Mtpa
Strategic convenience sites★	**2,950**	2,850
Electric vehicle charge points★	**>39,000**	>29,000
Hydrogen production (net)	**–**	–
Developed renewables to final investment decision★ (net)	**8.2GW**	6.2GW
Installed renewables capacity★ (net)	**4.0GW**	2.7GW

Key

TCFD	TCFD Recommendations and Recommended Disclosures

a In 2024 we revised our strategic targets and aims, retiring customer touchpoints per day.
b Conversion to mboe based on gasoline gallon equivalent (1mmbtu = 8.04 gallons).

★ See glossary on **page 351**

Pursuing a strategy that is consistent with the Paris goals

What we mean by Paris-consistent

The 2019 CA100+ resolution★ requires us to disclose the strategy that the board considers in good faith to be consistent with the Paris goals.

When we refer to 'consistency with Paris' we consider this to mean consistency with the world meeting the temperature goal set out in Articles 2.1(a) and 4.1 of the Paris Agreement on Climate Change★.

The Paris goals, which we support, were restated in the Baku Climate Pact at COP29 in Baku in November 2024.

We believe the world is on an unsustainable path, and the carbon budget to meet the Paris goals is running out.

bp's strategy is informed by these considerations. It is designed to create long-term value for shareholders, while enabling delivery of our net zero ambition. It is tested for resilience to the uncertainty of the energy transition across many different potential pathways, including various Paris-consistent pathways.

In the *bp Annual Report and Form 20-F 2021* we set out, based on **three key principles**, why the board considers our strategy to be consistent with the Paris goals. Here we set out, on the same three grounds, why the board continues to consider this to be the case.

Informed by Paris-consistent energy transition scenarios

The speed and nature of the energy transition are uncertain, and so we consider a range of scenarios from multiple sources including the *bp Energy Outlook 2024* to inform our beliefs about the energy transition and to develop and test our strategic thinking. This helps to reinforce our confidence in the robustness and resilience of our strategy to the range of uncertainty we face.

We are confident that our approach is science-based. We see the Intergovernmental Panel on Climate Change (IPCC) as the most authoritative source of information on the science of climate change, and we use it and other sources to inform our strategy. The IPCC highlights that there are a range of global pathways by which the world can meet the Paris goals, with differing implications for regions, industry sectors and sources of energy.

The *bp Energy Outlook 2024* examined recent developments and emerging trends in the global energy system, exploring the key uncertainties surrounding the energy transition. It included two main scenarios – one of which, Net Zero, we regard as Paris-consistent.

Energy outlook **page 7** and **bp.com/energyoutlook**

Strategic resilience

We believe our strategy positions bp for success and resilience in a Paris-consistent world – a world that is progressing on one of the many global trajectories considered to be Paris-consistent, and ultimately meets the Paris goals.

The strategy diversifies bp's portfolio and business interests, reducing the risk that challenges facing a single business area might adversely affect bp's strategic resilience.

In addition, within the inevitable constraints associated with factors such as long-term capital investments, contractual commitments and organizational capabilities at any given time, bp's ability to maintain its strategic resilience rests, in part, on the governance used to keep the strategy and associated targets and aims under review in light of new information and changes in circumstances.

In our climate-related financial disclosures on **page 50**, we describe how we have conducted an analysis to test our view of the resilience of our strategy, based on the Capital Markets Update presented on 26 February 2025, to different climate-related scenarios. This includes some scenarios that are classified by the World Business Council for Sustainable Development (WBCSD) to be consistent with well-below 2°C and 1.5°C outcomes[a].

As further explained on **page 51**, while the results of any such analysis must be treated with caution overall, this resilience test again reinforced our confidence in the continued resilience of our strategy to a wide range of ways in which the energy system could evolve throughout this decade, including in scenarios consistent with limiting temperature rise to 1.5°C.

The analysis also again highlighted that, while within the WBCSD scenarios lowest oil prices are associated with 1.5°C scenarios, there is considerable uncertainty – demonstrated by the range within, and overlap between, the prices indicated for each scenario family.

In the version of the WBCSD catalogue used for the analysis, the lowest oil price is associated with a 1.5°C scenario; however a number of the 1.5°C and well-below 2°C scenarios have oil prices in 2030 that are substantially higher than these – and when compared to bp's own central case oil price planning assumption for 2030, the oil price in a number of the well-below 2°C and 1.5°C scenarios is also higher.

Taking this into account, the analysis supported our belief that our strategy is financially resilient against the lowest prices associated with a Paris-consistent world in the WBCSD catalogue. This in turn supports our view that our strategy is resilient to such a Paris-consistent world.

a Our 2024 analysis used data from the WBCSD Climate Scenario Catalogue version 3.0, published on 16-05-2024 and downloaded on 13-11-2024.

Contributes to net zero

We believe that our strategy enables bp to make a positive contribution to the world achieving net zero greenhouse gas (GHG) emissions and meeting the Paris goals – outcomes which we believe to be in the best interests of bp as well as beneficial to society generally.

We see huge opportunity in the energy transition – the transformation of the energy system that we believe to be a necessary feature of the world's efforts to meet the Paris goals. There are many ways a company at the heart of the energy sector can make a meaningful contribution to the world getting to net zero. In addition to investing in our transition businesses★, these include: supporting collective action through participation in external initiatives and seeking to use the company's influence with trade associations that conduct climate-related advocacy; low carbon collaboration and support for others in their own decarbonization efforts (such as cities and corporates).

For example, we continue to advocate for policies that support net zero. Helping policymakers to design and put in place low carbon policies that support the transition to net zero can help deliver our strategy and capitalize on the opportunities associated with achieving the Paris goals, but the benefit of such actions, if successful, extends well beyond any implications for bp's own GHG metrics. That is because well-designed low carbon policies can also advance the decarbonization of a whole economy – something potentially of far greater impact than anything a single company can achieve through its own portfolio. We publish examples of our activity online at **bp.com/advocacyactivities**.

Some ways of contributing to helping the world get to net zero are more readily measured by quantitative metrics than others – but all can be important, whether or not they translate into GHG reductions for bp. For example, Lightsource bp operates with a develop, engineer, construct and farm-down business model that creates value through selling majority interests in assets it has developed to strategic partners.

Where Lightsource bp helps bp meet its own demand for cost competitive, low carbon power, including for power trading, EV charging, biofuels and green hydrogen★ this would show up in GHG metrics. However, where we do not directly sell that power, our development of the renewables is effectively 'invisible' in terms of our GHG metrics.

In December 2024, in Teesside, UK, bp and partners reached financial close on the Net Zero Teesside Power (NZT Power) and Northern Endurance Partnership (NEP) projects. The NEP aims to develop the infrastructure to transport and store up to an initial 4MtCO_2 annually from three Teesside-based carbon capture projects within the East Coast Cluster, with the ability to expand in the future.

Where the CO_2 being taken offshore for permanent storage is from local heavy industries this will not show up in bp's GHG metrics.

So while Lightsource bp, NZT Power and NEP projects support the Paris goals by increasing the low carbon options available to energy consumers, not all of their activities will be reflected in the metrics associated with bp's net zero aims.

Responding to increased shareholder interest in Paris consistency

In 2019 the board recommended that shareholders support a special resolution requisitioned by Climate Action 100+ (CA100+) on climate change disclosures. The CA100+ resolution passed with more than 99% of votes cast. This is the sixth year we have included responses throughout the annual report and we have adopted a similar approach to previous years.

The CA100+ resolution, which includes safeguards such as protections for commercially confidential and competitively sensitive information, is on **page 352**. Key terms related to this resolution response are indicated with ★ and defined in the glossary on **page 352**. These should be reviewed with the following information:

Element of the CA100+ resolution	Related content	Where
Strategy that the board considers in good faith to be consistent with the Paris goals.	Our strategy and business model	8 & 12
	Pursuing a strategy that is consistent with the Paris goals	10
How bp evaluates each new material capex investment★ for consistency with the Paris goals and other outcomes relevant to bp strategy.	Our investment process	20
Disclosure of bp's principal metrics and relevant targets or goals over the short, medium and long term, consistent with the Paris goals.	Key performance indicators	14
	Sustainability: net zero aims and targets	38
	See 'TCFD Metrics & Targets' for an overview	55
Anticipated levels of investment in: (i) Oil and gas resources and reserves. (ii) Other energy sources and technologies.	Our strategy	8
	Financial frame: disciplined investment allocation	18
	Investment in non-oil and gas	21
	Transition investment	39
bp's targets to promote operational GHG reductions.	Sustainability: net zero★ aims	38
Estimated carbon intensity of bp's energy products and progress over time.	Sustainability: net zero sales aim★	39
Any linkage between above targets and executive pay remuneration.	Directors' remuneration report	88
	2024 annual bonus outcome	96
	2025 remuneration policy	102

What makes us different

As an integrated energy company, we believe we have a world-class portfolio – a top-tier oil and gas business in attractive basins, and leading integrated positions and brands across the value chain. All underpinned by distinctive capabilities in trading, technology and partnerships.

Our purpose

Guiding what we do and how we operate.

Our purpose is to deliver energy to the world, today and tomorrow.

Our reset strategy

Our new strategy plays to our distinctive strengths and capabilities.

- Growing the upstream
- Focusing the downstream
- Investing with discipline in transition

Strategy, **page 8**

People and resources[a]

These are some of the people and resources in our business model that support how we create and preserve value for our stakeholders.

Incumbent capability

~11,600
engineers

~1,100
employees on graduate schemes

Sustainability at bp, **page 38**

Research and development

$301m
invested in research and development

~2,200
granted and pending patent applications held by bp and its subsidiaries

page 171

Energy sector experience

>110 years
in energy

~15 years
of *bp Energy Outlook* publications

The operating environment, **page 6**

Financial resources

$16.2bn
capital expenditure★

$27.3bn
operating cash flow★

Group performance, **page 24**

Energy resources

6,248mmboe
proved hydrocarbon reserves for the group[b]

8.2GW
developed renewables to FID★ (net)

Gas & low carbon energy, **page 28**
Supplementary information on oil and natural gas, **page 223**

a Data as at 31 December 2024.
b On a combined basis of subsidiaries and equity-accounted entities. See page 323 for more information on bp's oil and gas reserves.

Our business groups

This is how we are organized to deliver our strategy and deliver long-term shareholder value. Our three business groups are enabled by supply, trading & shipping and supported by five functions: finance; technology; strategy, sustainability & ventures; people, culture & communications; and legal.

Gas & low carbon energy

Integrating our existing natural gas capabilities with power trading and growth in low carbon businesses and markets, including wind, solar, hydrogen and carbon capture and storage.

page 28

Production & operations

The operational heart of bp, producing the hydrocarbon energy and products the world wants and needs – safely and efficiently.

page 31

Customers & products

Focusing on customers as the driving force for innovating new business models and service platforms to deliver the convenience, mobility and energy products and services of today and the future.

page 33

Delivering value for stakeholders[a]

We are committed to delivering long-term value for stakeholders.

Investors and shareholders

Includes our institutional and retail investors.

$5.0bn

total dividends distributed to bp shareholders
(2023 $4.8bn)

Employees

Our 100,500[c] people worldwide.

70%

employee engagement score from the Pulse annual employee survey
(2023 73%)

page 58

Society

The people, businesses and environment in the communities where we work.

$76m

supporting additional initiatives to benefit communities
(2023 $117m)

Customers

Including end-use consumers, B2B customers, and distributors.

2,950

strategic convenience sites★
(2023 2,850)

Governments and regulators

In the countries where we have existing or planned activities.

$10.6bn

corporate income tax and production tax paid
(2023 $11.9bn)

bp.com/tax

Partners and suppliers

Includes relationships with academia, industry and cities.

$146.6bn

in payments to suppliers for goods and services
(2023 $151.7bn)

bp.com/sustainability

c This figure reflects new acquisitions and companies we have taken full ownership of including bp bioenergy and Lightsource bp.

★ See glossary on **page 351**

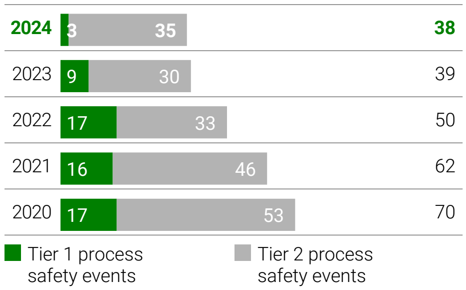
Key performance indicators

We assess the performance of the group across a wide range of measures and indicators that are consistent with our strategy.

Our key performance indicators (KPIs) provide a balanced set of metrics that give emphasis to both financial and non-financial measures. These help the board and leadership team assess bp's performance. Our leadership team uses these measures to evaluate operating performance and inform its financial, strategic and operating decisions.

Safety

Tier 1 and 2 process safety events★[ab]



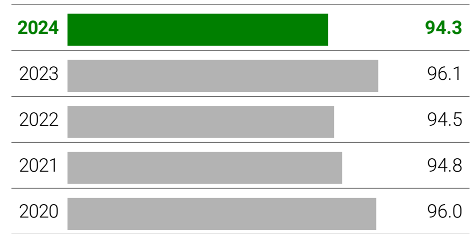
We track tier 1 and tier 2 events and report the aggregated outcome. Tier 1 events are losses of primary containment from a process of greatest consequence – causing harm to a member of the workforce, damage to equipment from a fire or explosion, a community impact or exceeding defined quantities (per API RP 754 tier 1 definitions). Tier 2 events are those of lesser consequence (per API RP 754 tier 2 definitions).

2024 performance

Our combined process safety events (PSEs) have generally decreased over the last 12 years, apart from in 2019. In 2024 we reported our lowest number of tier 1 PSEs – three, down from nine in 2023. However, our tier 2 PSEs increased to 35 (2023 30). Our total reported PSEs for 2024 were 38 (2023 39), see **page 56**.

Sustainable operations

Refining availability (%)



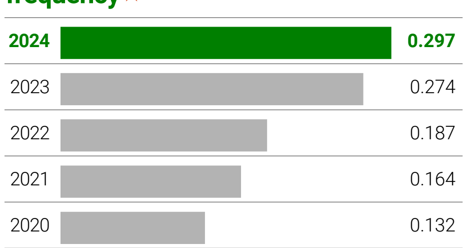
bp-operated refining availability represents Solomon Associates' operational availability for bp-operated refineries. The measure shows the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all mechanical, process and regulatory downtime.

Refining availability is an important indicator of the operational performance of our downstream businesses.

2024 performance

bp-operated refining availability decreased to 94.3% in 2024, mainly due to the impact of a power outage at our Whiting refinery.

Reported recordable injury frequency★[ab]

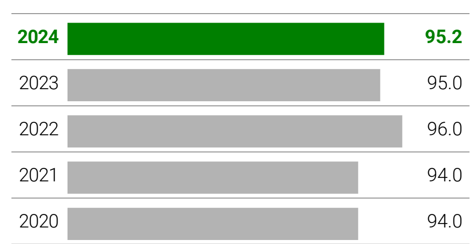


Reported recordable injury frequency (RIF) measures the number of reported work-related employee and contractor incidents that result in a fatality or injury per 200,000 hours worked.

2024 performance

In 2024, our RIF increased by 8.5%. Our businesses have identified underlying themes for these injuries and have developed plans intended to help reduce them in future. For more on safety, see **page 56**.

Upstream★ plant reliability (%)



bp-operated upstream plant reliability is calculated taking 100% less the ratio of total unplanned plant deferrals divided by installed production capacity, excluding non-operated assets and bpx energy. Unplanned plant deferrals are associated with the topside plant and, where applicable, the subsea equipment (excluding wells and reservoirs). Unplanned plant deferrals include breakdowns, which does not include Gulf of America weather-related downtime.

2024 performance

Upstream plant reliability in 2024 was marginally higher than in 2023.

Remuneration

To help align the focus of our executive management and executive directors with the interests of our shareholders, certain measures are used for executive remuneration.

Directors' remuneration report, **page 88**

Key

●	Used for remuneration policy
TCFD	TCFD Recommendations and Recommended Disclosures

a Exclusions to safety metrics – tier 1 and 2 process safety events may exist and recordable injury frequency may exist where entities that have been recently acquired or where bp has recently taken full ownership have been granted a deviation from specific reporting requirements in bp's Operating Management System (OMS)★ for an initial transitional period and data are not included in the reported metrics unless specifically noted. For the full year 2024 reporting period this includes Archaea Energy, TravelCenters of America, bp bioenergy and Lightsource bp.

b The metric includes reported PSEs occurring within bp's operational HSSE reporting boundary. That boundary includes bp's own operated facilities and joint ventures where bp is the operator. In some cases, we may also provide information about some joint venture activities where bp is not the operator.

Financial

Major project delivery

2024	**1**
2023	4
2022	2
2021	7
2020	4

We monitor the progress of our major projects to gauge whether we are delivering our core pipeline of projects under construction on time.

Projects take many years to complete, requiring differing amounts of resource, so a smooth or increasing trend should not be anticipated.

Major projects are defined as those with a bp net investment of at least $250 million, or considered to be of strategic importance to bp, or of a high degree of complexity.

2024 performance

We started up one major oil and gas project in 2024 – the Azeri Central East project in Azerbaijan. Furthermore, on 31 December first gas flowed to the FPSO at the Greater Tortue Ahmeyim project in Mauritania and Senegal.

Underlying replacement cost (RC) profit ($ billion)

	Profit (loss) for the year attributable to bp shareholders	Underlying RC profit for the year (non-IFRS)
2024	**0.4**	**8.9**
2023	15.2	13.8
2022	(2.5)	27.7
2021	7.6	12.8
2020	(20.3)	(5.7)

Underlying RC profit★ (non-IFRS) is a useful measure for investors because it is one of the profitability measures bp management uses to assess performance. It assists management in understanding the underlying trends in operational performance on a comparable year-on-year basis. It reflects the replacement cost of inventories sold in the period and is arrived at by adjusting for inventory holding gains and losses★, net impact of adjusting items★ and related taxation from profit or loss attributable to bp shareholders.

2024 performance

Profit for 2024 attributable to bp shareholders includes pre-tax net impairment charges of $5.1 billion. Reduction in the underlying RC profit reflects lower refining margins, lower realizations★, a lower gas marketing and trading result and a lower oil trading contribution, partly offset by lower taxation.

Operating cash flow ($ billion)

2024	**27.3**
2023	32.0
2022	40.9
2021	23.6
2020	12.2

Operating cash flow is net cash flow provided by operating activities, as reported in the group cash flow statement.

2024 performance

2024 primarily reflects lower profits from operations, partly offset by working capital movements.

Upstream unit production costs ($/boe)

2024	**6.17**
2023	5.78
2022	6.07
2021	6.82
2020	6.39

The upstream unit production cost is calculated as production cost divided by units of production. Production cost does not include ad valorem and severance taxes. Units of production are barrels for liquids★ and thousands of cubic feet for gas. Amounts disclosed are for bp subsidiaries only and do not include bp's share of equity-accounted entities.

2024 performance

Unit production costs increased, mainly reflecting the impact of portfolio changes.

Total shareholder return (%)

	ADS basis	Ordinary share basis
2024	**(11.9)**	**(11.0)**
2023	5.9	2.6
2022	36.9	50.1
2021	36.4	36.4
2020	(41.4)	(41.7)

Total shareholder return (TSR) represents the change in value of a bp shareholding over a calendar year (American Depositary Share (ADS) in USD, ordinary share in GBP). It assumes that dividends are reinvested to purchase additional shares at the closing price on the ex-dividend date.

2024 performance

Reduced TSR reflects a reduction in the share price.

Return on average capital employed (ROACE) (%)

	Profit (loss) for the period attributable to bp shareholders divided by total equity	ROACE (non-IFRS)
2024	**0.5**	**14.2**
2023	17.8	18.1
2022	(3.0)	30.5
2021	8.4	13.3
2020	(23.7)	(3.8)

ROACE★ (non-IFRS) gives an indication of a company's capital efficiency, dividing the underlying RC profit (loss) after adding back non-controlling interest and interest expense net of tax by the average of the beginning and ending balances of total equity plus finance debt, excluding cash and cash equivalents and goodwill as presented on the group balance sheet over the periods presented.

2024 performance

Profit for 2024 attributable to bp shareholders was $0.4 billion and total equity at 31 December 2024 was $78.3 billion. ROACE for 2024 reflected lower refining margins, lower realizations, a lower gas marketing and trading result and a lower oil trading contribution, partly offset by lower taxation.

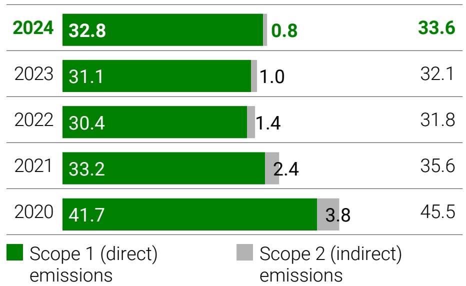
★ See glossary on **page 351**

Key performance indicators
continued

Non-financial

Greenhouse gas emissions[abcde] – operational control ($MtCO_2e$)

TCFD



We report Scope 1 and Scope 2 greenhouse gas (GHG) emissions material to our business on a carbon dioxide-equivalent basis. This KPI comprises Scope 1 (from running the assets within our operational control boundary) and Scope 2 (associated with importing electricity, heating and cooling that is bought in to run those operations) data covered by our net zero operations aim (to be net zero across our operations by 2050 or sooner). It comprises 100% of Scope 1 and 2 emissions or activities within bp's operational control boundary.

2024 performance

In 2024 our Scope 1 (direct) emissions were 32.8$MtCO_2e$ – an overall increase from 31.1$MtCO_2e$ in 2023. Of these Scope 1 emissions, 31.4$MtCO_2e$ were carbon dioxide and 1.5$MtCO_2e$ were methane[c]. Overall emissions increased due to project start-ups, operational growth in our low carbon businesses, temporary operational changes and operational issues in Tangguh, partially offset by the delivery of emissions reduction projects. In 2024 our Scope 2[d] (indirect) emissions, covered by bp's net zero operations★ aim, decreased by 0.2$MtCO_2e$, to 0.8$MtCO_2e$, compared with 2023. The continued use of lower carbon power agreements and a project at our Gelsenkirchen refinery to replace imported steam contributed to this decrease, see **page 38**.

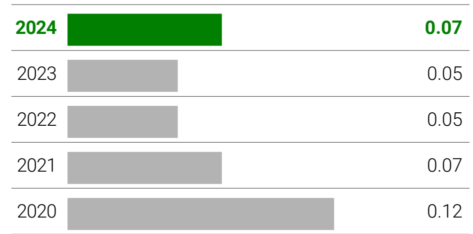
Basis of calculation[e]

bp's reported GHG emissions include methane (CH_4) and carbon dioxide (CO_2). Other GHGs are not included as they are not material to our operations. CH_4 emissions are converted to CO_2 equivalent using the 100-year global warming potential recommended by the Fifth Assessment Report (AR5) of the Intergovernmental Panel on Climate Change (IPCC).

Data is required to be submitted into the bp group reporting tool, OneCSR, in accordance with bp's Operating Management System (OMS)★ requirements, broadly based on the GHG Protocol Corporate Standard and the Ipieca Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions 2nd Edition, May 2011. The responsibility for quantifying and submitting GHG emissions for reporting is assigned to individual bp facilities and business departments, which are termed reporting units (RUs).

Methane intensity[af] (%)

TCFD



We define methane intensity★ as the amount of methane emissions from our upstream oil and gas operations as a percentage of the gas that goes to market from those operations. This applies to methane emissions within our operational control boundary, where we have the highest degree of control. Methane emissions from non-producing activities, such as exploration drilling, are excluded. In 2024 we started reporting methane intensity based on our new measurement approach across our major operated oil and gas assets.

2024 performance

Our methane intensity was 0.07% in 2024[f]. Methane emissions from upstream operations used to calculate this methane intensity increased by around 48% from 31kt in 2023 to 46kt in 2024, see **page 39**.

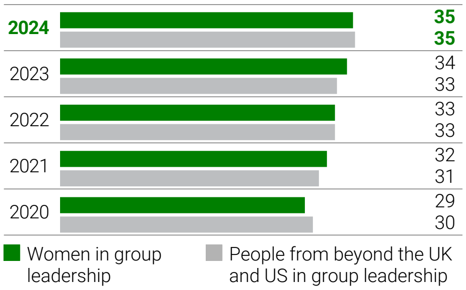
Basis of calculation[e]

All operated upstream assets report methane (CH_4) emissions on a 100% basis, including emissions from operated upstream oil and gas and also includes terminals and LNG facilities. Marketed gas production: all upstream gas reaching a market from bp-operated upstream assets, whether or not this is bp-owned product, and includes gas production from natural gas wells and associated gas from oil production wells. Throughput from bp-operated oil and gas terminals is excluded to avoid double counting despite their associated CH_4 emissions being included in the metric. CH_4 data is required to be submitted into the bp group reporting tool, OneCSR, in accordance with OMS requirements, broadly based on the GHG Protocol Corporate Standard and the Ipieca Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions 2nd Edition, May 2011. The responsibility for quantifying and submitting CH_4 emissions for reporting is assigned to individual bp facilities and business departments (RUs).

Key

●	Used for remuneration policy
TCFD	TCFD Recommendations and Recommended Disclosures

Diversity and inclusion[g] (%)



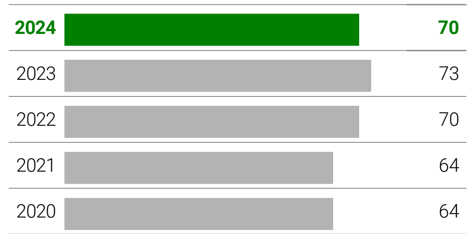
Our people are crucial to delivering our purpose and strategy. We aim to recruit talented people with diverse perspectives, backgrounds, skills and experiences, invest in their development and promote an inclusive culture.

Each year we report the percentage of women and individuals from countries other than the UK and the US among bp's group leaders.

2024 performance

The percentage of women in group leadership increased in 2024, continuing an upward trend over the previous five years. The percentage of people from beyond the UK and US in group leadership also increased by 2 points.

Employee engagement (%)



We conduct a Pulse annual employee survey to understand and monitor levels of employee engagement and identify areas for improvement.

2024 performance

The 2024 Pulse annual survey, which ran in August and September, saw our engagement score decrease by 3 points to 70%, in line with 2022 levels, and a completion rate of 82%. We also extended the survey to retail where we achieved an engagement score of 68% and completion rate of 77%. We continue to build engagement plans based on survey feedback and on real-time updates from our monthly snapshot, Pulse live.

Employee engagement, **page 58**

a These are our KPIs for the purposes of our disclosures pursuant to the UK CFD Regulations and Section 414CB (2A) (h) of the Companies Act 2006.
b Total (100%) Scope 1 (direct) GHG emissions from source activities operated by bp or otherwise within bp's operational control boundary. bp's reported GHG emissions include CH_4 and CO_2.
c Due to rounding some totals may not equal the sum of their component parts. This does not affect the underlying values.
d Scope 2 emissions on a market basis.
e Included as part of reporting under the Companies (Strategic Report) Climate-related Financial Disclosure Regulations 2022 (the UK CFD Regulations).
f In 2024 reported absolute methane emissions from upstream major oil and gas processing sites are based on our new measurement approach. Prior to 2024 these emissions were calculated using a different methodology and therefore the methane intensity reported in those years and calculated using that data does not directly correlate to progress towards delivering the 2025 target. Prior year data is provided for information purposes, and we do not seek to directly compare prior years.
g Relates to bp employees.

Operating within a resilient and disciplined financial frame

Our financial frame sets out how we allocate cash that we generate to strengthen our balance sheet, invest with discipline to grow the value of bp and deliver resilient shareholder distributions.

Our financial frame

Balance sheet

$14-18bn

Net debt★ target by end 2027[a]

'A' range credit metrics through cycle

Shareholder distributions

Resilient dividend

Expect annual increase of the dividend per ordinary share of at least 4%[b]

Share buybacks

Excess cash shared through buybacks over time

30-40%

of operating cash flow★ distributed as dividends and share buybacks[bc]

Capital expenditure

~$15bn

in 2025

$13-15bn

in 2026-27

Disciplined investment allocation, assessed against a set of balanced criteria

a Potential proceeds from any transactions related to *Castrol* strategic review and announcement to bring a strategic partner into Lightsource bp will be allocated to reduce net debt.
b Subject to board discretion each quarter, taking into account factors including outlook for cash flow, share count reduction from buybacks and maintaining 'A' range credit metrics.
c Includes offsetting any dilution from employee share schemes over time.

Resilient dividend

We continue to maintain a resilient dividend policy within our disciplined financial frame.

Since the fourth quarter of 2023 our dividend per ordinary share has grown by 10% to 8.00 cents.

Based on our current forecasts and subject to the board's discretion each quarter, we expect increases in the dividend per ordinary share of at least 4% per annum.

Stronger balance sheet

We are committed to strengthening the balance sheet and are now targeting net debt of between $14-18 billion by the end of 2027. Any potential proceeds from the strategic review of *Castrol* and Lightsource bp transactions will be dedicated to strengthening the balance sheet.

For the full-year 2024, finance debt increased from $52.0 billion at the end of 2023 to $59.5 billion, primarily reflecting net long-term debt issuances, and net debt increased from $20.9 billion to $23.0 billion.

Disciplined investment allocation

We will continue to invest with discipline, driven by value, and focused on delivering returns.

Investment is allocated across our businesses based on a set of criteria that balances strategic alignment, hurdle rates, volatility, integration value, sustainability and risk (see **page 22**).

In 2024 capital expenditure★ was $16.2 billion. We expect capital expenditure to be around $15 billion in 2025 and our capital expenditure frame for 2026 and 2027 is reduced to $13-15 billion per annum. This includes expenditure on inorganic opportunities. Within the capital frame, on average ~$10 billion per year will be allocated to oil and gas, of which ~70% is expected to be allocated to oil and 30% to gas. In customers and products, we are progressively focusing capital expenditure from ~$4 billion in 2024 to ~$3 billion by 2027. In low carbon energy, we expect capital expenditure, on average, will be less than $800 million per year through 2027, around half of which is allocated to hydrogen and CCS projects already through FID.

Share buybacks

Share buybacks remain a core part of our investor proposition. Our intention remains to share excess cash with investors through buybacks. Subject to board discretion, we expect total distributions, including dividend and buyback, to be in the range of 30-40% of operating cash flow over time, including buybacks to offset dilution from employee share schemes.

We announced share buybacks of $7 billion for 2024 and between the end of the first quarter 2021 and 31 December 2024, we have reduced our shares in issue by 22%.

In setting the dividend per ordinary share and buyback each quarter, the board will continue to take into account factors including the cumulative level of and outlook for cash flow, share count reduction from buybacks and maintaining 'A' range credit rating metrics.

Our investor proposition

Our strategy is being fundamentally reset. We are reallocating capital to drive growth from our highest returning businesses. And we are focused on driving improved performance. This is all in service of growing long-term shareholder value. It's underpinned by a plan to deliver compelling adjusted free cash flow★ and strong returns growth, supporting resilient distributions and a stronger balance sheet. We believe bp has a compelling investor proposition.

Resetting strategy
- Growing upstream
- Disciplined transition investment

Reallocating capital
- Reallocating and reducing capital expenditure★
- Significant divestment programme

Driving performance
- Improving downstream
- Cost efficiency

Compelling adjusted free cash flow growth
>20%

Compound annual growth rate (CAGR)★ from 2024-27[a]

Strong returns growth
>16%

ROACE★ in 2027[a]

Resilient distributions
30-40%

Total distribution of operating cash flow[bc]

Stronger balance sheet
$14-18bn

Net debt target by end 2027[d]

Lower operational emissions
45-50%

Reduction aim across Scope 1 and 2 by 2030[e]

More information
Our strategy and primary targets, **page 8**
Sustainability, **page 38**

2025 guidance

	2024 actual	2025 guidance
Upstream reported production (guidance is both reported and underlying production★)	2.4mmboe/d	Reported production to be lower/underlying production to be slightly lower than 2024
Total capital expenditure★	$16.2bn	Around $15bn
Depreciation, depletion and amortization	$16.6bn	Broadly flat compared with 2024
Divestments and other proceeds[f]	$4.2bn	Around $3bn, weighted towards the second half
Gulf of America oil spill payments[g] (pre-tax)	$1.2bn	Around $1.2bn including $1.1bn pre-tax to be paid during the second quarter
Other businesses & corporate underlying annual charge	$0.6bn	Around $1.0bn
Underlying effective tax rate★	41%[h]	Around 40%[i]

a At $70/bbl Brent, $4/mmBtu Henry Hub, and $17/bbl refining marker margin, all 2024 real.
b Subject to board discretion each quarter taking into account factors including outlook for cash flow, share count reduction from buybacks and maintaining 'A' range credit metrics.
c Includes offsetting any dilution from employee share schemes over time.
d Potential proceeds from any transactions related to *Castrol* strategic review and announcement to bring a strategic partner into Lightsource bp will be allocated to reduce net debt.
e Reduction in emissions against 2019 baseline, on a CO_2e basis.
f Divestment proceeds★ are disposal proceeds as per the group cash flow statement. See page 26 for more information on divestment and other proceeds.
g See Financial statements – Note 22 for more information on payables related to the Gulf of America oil spill.
h Nearest equivalent GAAP IFRS measure: effective tax rate 82%.
i Underlying effective tax rate★ is sensitive to the impact that volatility in the current price environment may have on the geographical mix of the group's profits and losses.

Our investment process

How we use price assumptions

Our price assumptions are used for our investment appraisal processes. They are also used to inform decisions about internal planning and the value-in-use impairment testing of assets for financial reporting.

The role of price assumptions

Our decisions on individual investments are informed by our view of the price environment and consider the balanced investment criteria discussed below.

Our price assumptions continue to reflect a range of possibilities, including that the transition to a lower carbon economy and energy system could accelerate. Our investment appraisal assumptions, which take a long-term perspective, focus on the fundamental trends affecting the energy sector and our businesses.

From January 2024 until January 2025, we held our key investment appraisal price assumptions constant at the levels set out in the *bp Annual Report and Form 20-F 2023*. For relevant investment cases assessed from February 2025, we have applied and plan to apply the prices shown in the key investment appraisal assumptions table (right) for our central price case. Brent oil and Henry Hub gas assumptions average around \$64/bbl and \$4.0/mmBtu respectively (2023 \$ real) from 2025 to 2050. We consider these prices to be broadly consistent with a range of transition paths compatible with meeting the Paris goals, but they do not correspond to any specific Paris-consistent scenario. We also consider a range of other price assumptions in investment appraisals, including product and market-specific prices relevant to individual investment cases.

We apply carbon prices rising from \$50/tCO_2e in 2025 to \$135/tCO_2e in 2030 and \$200/tCO_2e by 2050 (2023 \$ real) in certain cases (see box, right).

Impairment testing

Our best estimate of future prices for use in value-in-use impairment testing continues to be based on our investment appraisal price assumptions, with quarterly review of near-term prices to confirm that the assumptions appropriately reflect any changes to expectations due to short-term market trends.

Impairment price assumptions were held constant in 2024 at the levels disclosed in the *bp Annual Report and Form 20-F 2023* until the fourth quarter, when the updated investment appraisal price assumptions shown below were used for value-in-use impairment testing.

For investment appraisal, potential future operational emissions costs that may be borne by bp as a result of an investment are included as bp costs, as described in the box below (generally without assuming incremental revenue associated with those emissions), in order to incentivize engineering solutions that reduce operational carbon emissions on projects. For the treatment of emission cost assumptions in value-in-use impairment testing, see Financial statements – **Note 1**.

Key investment appraisal assumptions[a] TCFD

2023 \$ real	up to 2030	2040	2050
Brent oil (\$/bbl)	70	63	50
Henry Hub gas (\$/mmBtu)	4.0	4.0	4.0
Refining marker margin (RMM)[b] ★ (\$/bbl)	14	12	9

In addition to the prices shown we also test whether investments meet our return expectations (see page 22) using \$60/bbl Brent oil price series.

Carbon price TCFD

2023 \$ real	2030	2040	2050
Carbon (\$/tCO_2e)	135	175	200

a The values in the table represent the central case.
b The disclosed RMM assumption in the table excludes carbon pricing impacts and assumes a normalized cost of renewable identification numbers (RINs).

Investment process price assumptions

All investments are evaluated against relevant price assumptions for oil, natural gas, refining margins or other commodities across a range of alternative price or margin series (typically a central, upper and lower series). In addition, all investment cases with anticipated annual operational GHG emissions (Scope 1 and 2) above 20,000 tonnes of CO_2 equivalent (bp net), must estimate those anticipated GHG emissions and include an associated carbon cost in the investment economics, using the carbon prices above.

Our investment price assumptions place some weight on scenarios in which the transition to a low carbon energy system is sufficiently rapid to meet the goals of the Paris Agreement, as well as scenarios in which the transition may not be sufficiently rapid. They also place some weight on a range of other factors that can drive prices, and which are not directly related to the Paris goals.

These price assumptions do not link to specific scenarios or outcomes, but instead try to capture the range of different possibilities surrounding the future path of the global energy system. The nature of the uncertainty means that the price ranges inevitably reflect considerable judgement. The ranges are reviewed and updated as necessary, as our understanding of and judgements about the energy transition evolve.

In addition to consideration of a range of price assumptions, investment cases also assess the impact of alternative assumptions covering other selected variables relevant to the economics of the investment. These variables may include cost, schedule, resources, policy changes, or other areas of uncertainty, to assess the robustness of investment cases to a range of other factors.

Investment governance and evaluating consistency with the Paris goals

Governance framework

bp's framework for investment governance seeks to ensure that investments align with our strategy, can be accommodated within our prevailing financial frame, and add shareholder value. It enables investments to be assessed in a consistent way against a range of criteria relevant to our strategy, including environmental and other sustainability criteria.

Investments follow an integrated stage-gate process designed to enable our businesses to choose and develop the most attractive investment cases. A balanced set of investment criteria is used (see **page 22**). This allows for the comparison and prioritization of investments across a diverse range of business models.

The governance framework specifies that proposed investments are evaluated using relevant assumptions, including carbon prices for projected operational emissions where applicable. It also sets out requirements for assurance by functions independent of the business before a final investment decision (FID) is taken.

The role of the board

The board assesses capital allocation across the bp portfolio, including the level and mix of capital expenditures★ and divestments, strategic acquisitions, distribution choices and deleveraging, as well as reviewing certain investment cases for approval.

Resource commitment meeting

For acquisitions and organic capital investments above defined financial thresholds, investment approval is conducted through the executive-level resource commitment meeting (RCM), which is chaired by the chief executive officer. The RCM reviews the merits of each investment case against a balanced set of criteria (see **page 22**) and considers any key issues raised in the assurance process.

The CA100+ resolution★ requires bp to disclose how we evaluate the consistency of new material capex investments★ with (i) the Paris goals and (ii) a range of other outcomes relevant to bp's strategy.

bp's evaluation of the consistency of such investments with the Paris goals was undertaken by the RCM for new material capex investments sanctioned in 2024 (see **page 23**).

bp's evaluation of an investment's consistency with 'a range of other relevant outcomes' is achieved by considering its merits against bp's balanced investment criteria, described on **page 22**.

bp board
Reviews and approves investment cases of more than $3 billion for resilient hydrocarbons, more than $1 billion for all transition or low carbon investments★ and any significant inorganic acquisition that is exceptional or unique in nature.

Resource commitment meeting
Forum for executive management's review and approval of investments related to existing and new lines of business above $250 million, or $25 million for acquisitions, or which exceed the relevant EVP's financial authority, and any project considered strategically important such as a new market entry.

Investment allocation committees
EVP-level forums to review and approve investment cases within a business group as per individual EVP financial authority (up to $250 million, or typically $25 million for acquisitions).

Business group investment governance meetings
SVP-level forums that review and approve investment cases within a business group or function, up to the individual SVP's financial authority.

Cross-group meetings
Forums that facilitate discussions across businesses and functions, to support project development, sensitivity analysis, integration opportunities and risk assessment ahead of investment committee meetings.

Investment in non-oil and gas

In 2024 transition growth investment★[a] was $3.7 billion, compared to $3.8 billion in 2023 (see **page 39**).

Bioenergy: Our biogas operation, Archaea Energy, continued its growth and using its modular plant design it started up nine new renewable natural gas (RNG)★ plants in 2024 (see **page 33**).

EV charging: Together with our strategic convenience site★ networks, our investment in EV charging is helping us to offer lower carbon mobility solutions to more customers. In 2024 examples include the opening of our standalone *Aral* EV charging *Gigahub*, in Germany, with 28 charge points. And in China, *bp pulse* installed 2MWh batteries at a charging hub in Shenzhen. We continue to build scale in our EV charging network in key markets (see **page 33**).

Convenience: In 2024 we continued strategic investment in support of high-grading our retail fuels and convenience portfolio, including continued investment in TravelCenters of America, which bp acquired in 2023 (see **page 33**).

Hydrogen and CCS: We are high-grading and focusing our hydrogen portfolio – prioritizing projects in jurisdictions where we have an adequate regulatory framework, access to the value chain – including our own or customer demand – linkage to carbon capture and access to competitive renewable power. In 2024 we made final investment decisions on four hydrogen/CCS projects (see **page 29**). For example we were granted funding to help support the development of a 100MW green hydrogen★ project next to our Lingen refinery in Germany. The plant could produce up to 11,000 tonnes of green hydrogen annually. The final investment decision was taken in December 2024.

Renewables & power: In April 2024 we announced that we took ownership of Equinor's 50% stake in the Beacon Wind US offshore wind projects. In December we announced that bp and JERA Co., Inc will, subject to regulatory approvals and closing conditions being met, join forces to create a global wind joint venture★ (see **page 28**).

Low carbon activity investment

In 2024 low carbon activity investment★, a subset of our total transition growth investment, accounted for 80% of our total transition growth investment (67% in 2023). It increased from $2.5 billion in 2023 to $3.0 billion in 2024, reflecting higher investment in bioenergy, EV charging and wind businesses.

a In February 2025 bp announced that we have retired the concept of transition growth★ engines going forward.

Our investment process continued

Balanced investment criteria

All investment cases must set out their investment merits and are considered against a set of six balanced investment criteria –although investment decisions may also take other factors into account as appropriate. This standardized approach is intended to create a level playing field for decision making and allows portfolio-wide comparisons of investment cases. The decision to endorse an investment based on the information provided represents our evaluation that it is consistent with what the 2019 CA100+ resolution★ refers to as 'a range of other outcomes relevant to bp's strategy'.

The **six** balanced investment criteria are:

Strategic alignment: For all investment cases, we consider whether the investment supports delivery of our strategy, including our net zero aims. We also assess if the investment case involves distinctive capability that bp has, or intends to develop, and whether it adds to an existing 'scale' business within the portfolio or could help us create one.

Safety and risks: For all investment cases, we provide an assessment of the key risks to the investment that have a significantly higher probability than usual or have a significantly greater impact (relative to the size of the project) were they to occur. Safety risk management at bp is underpinned by our Operating Management System (OMS)★, which is designed to help us sustainably deliver safe, reliable and compliant bp operations.

Sustainability: For all investment cases, we consider how any proposed business opportunity is connected to the energy transition, societal needs and the environment. This approach is underpinned by our purpose and sustainability frame. All RCM cases must consider significant impacts of an investment on key sustainability aims, informed by our sustainability assessment template for investment cases (for our use of carbon prices, see box on **page 20**).

Investment economics: For all investment cases, we consider investment economics against a range of relevant measures. Depending on the nature of the investment case, these may include return expectations (e.g. internal rate of return or IRR), net present value, discounted payback and profitability index, reflecting assumptions about relevant commodity prices, margins and carbon prices (see **page 20**). The forward economics of an investment case are considered against the differentiated IRRs applicable to that case at the time of the investment decision, depending on the business. We also refer to these expectations as hurdle rates; although, as noted, each case is assessed according to its combined merit against our full set of balanced criteria.

1. For our upstream business (including biogas), we seek an IRR of 15%.
2. For our downstream business (including EV charging and biofuels), we seek portfolio-level returns in excess of 15%.
3. For hydrogen and CCS, we expect levered returns in the mid-teens including farm-down and integration value.

For each investment, the relevant return expectations above are assessed using our central price assumptions. For additional capital discipline for investments in oil and gas production, we also compare the central price hurdle above (15%) to a case in which the Brent oil price starts at $60/bbl and later declines to the level of our key appraisal assumptions by 2050 (see **page 20**). In addition, for investments in our oil and gas and refined products businesses, as well as any other investments that do not fall within one of the specific businesses set out above, we compare the IRR in our lower-price case to a cost of capital hurdle rate.

Volatility and rateability: Our investment economics metrics also consider the degree of uncertainty of the cash flows when considering investment cases. For example, some cases have more certainty of future costs and revenue projections. Variation in net present values for the key variables in an investment case are quantified by sensitivity analysis to give a range of potential outcomes against our key investment hurdles.

Optionality and integration: Our assessment considers the degree of optionality offered by a project – the ability to adapt our business to changing circumstances. This could be an option to sell a product with a floor price, or the right to purchase additional equity in a joint venture at specific terms. Other types of options include the right to develop (or not develop) extensions to existing projects, or to change the course of a project's development depending on market circumstances. We likewise seek out integration along value chains across multiple products, services, geographies and customers. For example, our gas production can supply liquefaction plants whose LNG is monetized by our trading business. Likewise, carbon sequestration projects may allow us to add value to our gas production by reducing carbon intensity.

Paris consistency evaluation process

Our new material capex investments★ are intended to support the delivery of bp's strategy.

For evaluations conducted in 2024, investments in scope for evaluation were defined as:

- **New:** investment in a new project, or extension of an existing project/asset, or share of an entity that is new to bp, or a substantial increase in bp's share.
- **Material:** more than $250 million capex investment.

Quantitative evaluations

For our investment economics and sustainability investment criteria we considered quantitative guide levels, as set out below, to inform the evaluation of each investment's consistency with the goals of the Paris Agreement. For evaluations in 2024 we used the central price IRR and other economic hurdles as set out in the *bp Annual Report and Form 20-F 2023* (page 32). As in previous years, we reduced our operational carbon intensity★ guide levels, in line with our decreasing portfolio average. As our approach matures with experience, we may continue to adjust or supplement our methodology. There may be instances when new material capex investments are evaluated as consistent with the Paris goals despite either the economic or sustainability guide levels not being met. The RCM may also take account, in its Paris consistency evaluation, of the six balanced investment criteria using qualitative assessments.

Investment economics: We calculated economic indicators using our central price, and where applicable, our lower price cases, and applying our carbon price assumptions to relevant operational GHG emissions. (For our current key central case oil and natural gas price assumptions, see **page 20**, where we also set out our view on their consistency with achieving the Paris goals). We then compared the economic indicators to the relevant economic guide level (see below), based on the corresponding hurdles. We typically target a threshold of >1.0x the relevant IRR guide level, and <1.0x any relevant payback guide level, as set out in the *bp Annual Report and Form 20-F 2023* (page 32).

Sustainability: Where appropriate, we compared the expected operational carbon intensity of the investment relative to that of the portfolio average shown in the *bp ESG Datasheet 2023* for the segment or the related business activity (upstream and refining). We normally target a ratio of less than 100%, meaning that the investment is expected to reduce the average operational carbon intensity of the relevant portfolio. The potential impact of new material capex investments on bp's net zero aims is a further consideration.

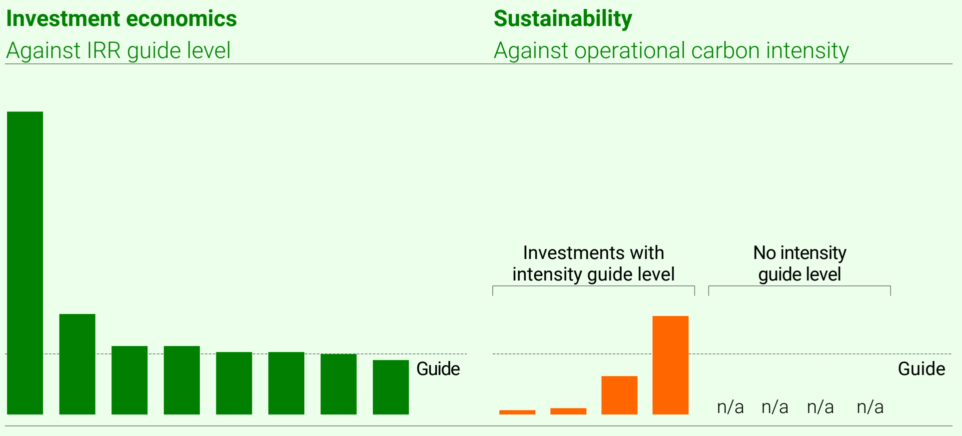
Evaluation outcome

In 2024 eight new material capex investments were approved[a]. All were evaluated as being consistent with the Paris goals, taking into account both quantitative and qualitative evaluations and the balanced criteria above.

Evaluation of investment performance against quantitative guide levels[b]

Seven of the eight investments exceeded the relevant IRR guide level as shown in the chart. The IRR of the remaining investment was slightly below its central price IRR hurdle.

Three of the four upstream hydrocarbon projects had emissions intensities below the relevant upstream intensity guide level. The other upstream investment had an emissions intensity above the guide level, but was expected to reduce our operational emissions intensity in the region. The four other investments were in businesses for which there was no applicable carbon intensity guide. These latter investments are shown as 'n/a' in the operational carbon intensity chart.



Decisions taken in 2024

In 2024 there were eight new material capex investment decisions evaluated for Paris consistency, shown here in the order the investment decisions were made:

Brazilian biofuels: In June bp agreed to take full ownership of our Brazilian biofuels joint venture, acquiring Bunge's 50% interest. The acquisition is expected to have capacity to produce around 50,000 barrels a day of ethanol equivalent from sugar cane through the business's 11 agro-industrial units across five Brazilian states.

Kaskida: In July bp approved its final investment decision in the Kaskida project in the US Gulf of America. The new floating platform is expected to have nameplate production capacity of 80,000 barrels of oil per day. It will leverage simplified, standardized and cost-efficient design, which is expected to be replicated in future projects.

Ruwais LNG: In July bp announced we had agreed to take a 10% interest in a new ADNOC-operated LNG facility in Abu Dhabi, deepening our relationship with our longstanding partner. The project has a planned total capacity of 9.6Mtpa. The investment is consistent with bp's strategy to develop competitive gas positions as we grow our LNG portfolio.

Coconut gas development: In August bp and EOG agreed to form a 50:50 joint venture for the Coconut development with EOG as operator. This partnership for the Coconut development is part of bpTT's strategy to grow its gas business and help to unlock the energy future of Trinidad and Tobago.

Tangguh UCC: In November bp and partners gave the go-ahead for the Tangguh UCC project in Papua Barat, Indonesia. The project has three components: the Ubadari field; a gas compression facility; and a carbon capture, use and storage (CCUS) project. It has the potential to unlock around 3 trillion cubic feet of additional gas resources in Indonesia to help meet growing energy demand in Asia. The CCUS component is expected to sequester around 15MtCO_2 during its initial phase from Tangguh's natural gas production, reducing overall CO_2 emissions intensity from operations at Tangguh.

Northern Endurance Partnership (NEP): In December bp and partners made their final investment decision for NEP, a joint venture between bp, Equinor and TotalEnergies, which is the CO_2 transportation and storage provider for the UK's East Coast Cluster (ECC).

The Teesside onshore NEP infrastructure is expected to serve the Teesside-based carbon capture projects – NZT Power, H2Teesside and Teesside Hydrogen CO_2 Capture. We expect around 4MtCO_2 per year from these projects will be transported and stored from 2027.

Net Zero Teesside Power (NZT Power): Also in December bp and partners took a final investment decision in NZT Power, a joint venture between bp and Equinor, which could generate up to 742MW of flexible, dispatchable low carbon power. Up to 2MtCO_2 per year will be captured at the plant, and then transported and securely stored in subsea storage sites in the North Sea.

Lingen Green Hydrogen: In December bp made a final investment decision for the Lingen Green Hydrogen project in Germany, which will be its first fully-owned and operated large-scale green hydrogen★ facility. The project is expected to install a 100MW electrolyser capacity capable of producing an average of 10-11kt of green hydrogen per year from 2027. The renewable power needed for the electrolyser is expected to be supplied by offshore wind generation.

a The RCM also approved two investment cases in our low carbon energy business with capital investment above $250 million, which are not included in the evaluation information presented above. This is because one did not reach a final investment decision during 2024 and the other was a transaction to progress certain bp low carbon energy assets by contributing them to a joint venture. All of the assets that were material had been previously disclosed as new material capex investments in bp's Annual Report and Form 20-F for the relevant year.

b The 2024 investments have been compared to relevant guides (as applicable to the evaluation of each investment) and are presented here in order of the ratio to the relevant central-price case IRR guide level (or where there was no relevant central price IRR guide level, the lower price one), and separately in order of the ratio to the relevant emissions intensity guide level. As a result, the evaluations against the economic and sustainability benchmarks do not necessarily follow the same order.

★ See glossary on **page 351**

Laying the foundation for growth

$0.4bn
profit attributable to bp shareholders
(2023 profit $15.2bn)

$8.9bn
underlying replacement cost (RC) profit★
(2023 profit $13.8bn)

$27.3bn
operating cash flow★
(2023 $32.0bn)

"bp delivered operating cash flow of $27.3 billion. During the year, we made strong progress on cost savings, achieving $0.8 billion of structural cost reduction★. We raised the dividend per ordinary share by 10% and delivered $7 billion of share buybacks. Our focus on capital discipline and strengthening the balance sheet continues into 2025."

Kate Thomson
Chief financial officer

Financial and operating performance

$ million except per share amounts

	2024	2023	2022
Sales and other operating revenues	**189,185**	210,130	241,392
Profit before interest and tax	**11,297**	27,348	18,039
Finance costs and net finance income/expense relating to pensions and other post-employment benefits	**(4,515)**	(3,599)	(2,634)
Taxation	**(5,553)**	(7,869)	(16,762)
Profit (loss) for the year	**1,229**	15,880	(1,357)
Non-controlling interest	**(848)**	(641)	(1,130)
Profit (loss) for the year attributable to bp shareholders	**381**	15,239	(2,487)
Inventory holding (gains) losses★, before tax	**488**	1,236	(1,351)
Taxation charge (credit) on inventory holding gains and losses	**(119)**	(292)	332
Replacement cost (RC) profit (loss)★	**750**	16,183	(3,506)
Net (favourable) adverse impact of adjusting items★[a], before tax	**9,344**	(1,143)	29,781
Total taxation charge (credit) on adjusting items	**(1,179)**	(1,204)	1,378
Underlying RC profit	**8,915**	13,836	27,653
Adjusted EBIDA★	**31,161**	34,345	45,695
Adjusted EBITDA★	**38,012**	43,710	60,747
Dividend paid per ordinary share (cents)	**30.540**	27.760	22.932
Dividend paid per ordinary share (pence)	**23.720**	22.328	18.624
Profit (loss) per ordinary share (cents)	**2.38**	87.78	(13.10)
Profit (loss) per ADS (dollars)	**0.14**	5.27	(0.79)
Underlying RC profit per ordinary share★ (cents)	**54.40**	79.69	145.63
Underlying RC profit per ADS★ (dollars)	**3.26**	4.78	8.74
Adjusting items[a]			
Gains on sale of businesses and fixed assets	**670**	361	3,866
Net impairment and losses on sale of businesses and fixed assets	**(6,930)**	(5,838)	(5,920)
Environmental and related provisions	**(181)**	(647)	325
Restructuring, integration and rationalization costs	**(222)**	37	34
Fair value accounting effects (FVAEs)[b]	**(1,852)**	9,403	(3,501)
Rosneft	**–**	–	(24,033)
Gulf of America oil spill	**(51)**	(57)	(84)
Other	**(273)**	(1,711)	(43)
Total before interest and taxation	**(8,839)**	1,548	(29,356)
Finance costs	**(505)**	(405)	(425)
	(9,344)	1,143	(29,781)
Adjusting items total taxation	**1,179**	1,204	(1,378)
	(8,165)	2,347	(31,159)

a See page 313 for more information.
b See page 314 for information on the cumulative impact of FVAEs.

At 31 December 2024 the group's reportable segments are gas & low carbon energy, oil production & operations and customers & products. Each is 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. See Financial statements – **Note 5** Segmental analysis.

Results

The profit for the year ended 31 December 2024 attributable to bp shareholders was $0.4 billion, compared with $15.2 billion in 2023. Adjusting for inventory holding losses, RC profit was $0.8 billion, compared with $16.2 billion in 2023.

After adjusting RC profit for a net adverse impact of items, which bp has classified as adjusting (adjusting items) of $8.2 billion (on a post-tax basis), underlying RC profit for the year ended 31 December 2024 was $8.9 billion. The result reflected lower refining margins, lower realizations, a lower gas marketing and trading result and a lower oil trading contribution, partly offset by lower taxation.

For 2023, after adjusting RC profit for a net favourable impact of adjusting items of $2.3 billion (on a post-tax basis), underlying RC profit was $13.8 billion. The result reflected lower realizations, the impact of portfolio changes, the impact of lower refining margins and a lower oil trading performance.

For a discussion of bp's financial and operating performance for the years ending 31 December 2022 and 31 December 2023, see *bp Annual Report and Form 20-F 2023*, pages 35-47.

Adjusting items

In 2024 the net adverse pre-tax impact of items, which bp has classified as adjusting (adjusting items) was $9.3 billion including:

- Adverse fair value accounting effects (FVAEs) relative to management's measure of performance of $1.9 billion primarily due to an increase in the forward price of LNG during 2024, compared to a decline in 2023 and the adverse impact of the fair value accounting effects relating to the hybrid bonds in 2024 compared to the favourable impact in 2023.
- Net impairment and losses on sale of businesses and fixed assets includes a loss of $1.1 billion relating to the sale of the ground fuels business in Türkiye (see Financial statements– **Note 2**) and net impairment charges of $5.1 billion (see Financial statements– **Note 4**).
- In addition, $0.5 billion net impairment charges were reported through equity-accounted earnings (reported within the 'other' category).
- The other category also includes a $0.5 billion gain relating to the remeasurement of bp's pre-existing 49.97% interest in Lightsource bp and a $0.5 billion gain relating to the remeasurement of certain US assets excluded from the Lightsource bp acquisition (see Financial statements – **Note 3** for further information); and recognition of onerous contract provisions related to the Gelsenkirchen refinery. The unwind of these provisions will be reported as an adjusting item as the contractual obligations are settled.

In 2023 the net favourable pre-tax impact of adjusting items was $1.1 billion including:

- Favourable FVAEs relative to management's measure of performance of $9.4 billion primarily due to a decline in the forward price of LNG during 2023. Under IFRS, reported earnings include the mark-to-market value of the hedges used to risk-manage LNG contracts, but not of the LNG contracts themselves. The underlying result includes the mark-to-market value of the hedges but also recognizes changes in value of the LNG contracts being risk managed. The impacts of FVAEs relative to management's internal measure of performance are provided on **page 314**.
- Net impairment charges of $5.7 billion largely as a result of changes in the group's price and discount rate assumptions, activity phasing and economic forecasts (in particular related to the Gelsenkirchen refinery).
- In addition, $1.3 billion net impairment charges were reported through equity-accounted earnings (reported within the 'other' category), of which $1.1 billion relates to our US offshore wind projects.

See Financial statements – **Note 4** for more information on impairments, and **pages 313 and 314** for more information on adjusting items and FVAEs.

Taxation

The charge for corporate income taxes was $5,553 million in 2024 compared with $7,869 million in 2023. The effective tax rate (ETR) on the profit before taxation for the year in 2024 was 82%, compared with 33% in 2023. The ETR on the profit before taxation for the year in 2024 and in 2023 was impacted by fair value accounting effects and other adjusting items. Excluding inventory holding impacts and adjusting items, the underlying ETR★ in 2024 was 41% compared with 39% in 2023. The underlying ETR in 2024 is higher due to changes in the geographical mix of profits. The underlying ETR for 2025 is expected to be around 40% but it is sensitive to a range of factors, including the volatility of the price environment and its impact on the geographical mix of the group's profits and losses. Underlying ETR is a non-IFRS measure. A reconciliation to IFRS information is provided on **page 360**.

Outlook for 2025

2025 guidance

- bp expects reported upstream★ production to be lower and underlying upstream production★ to be slightly lower compared with 2024. Within this, bp expects underlying production from oil production & operations to be broadly flat and production from gas & low carbon energy to be lower.
- In its customers business, bp expects growth including a full year contribution from bp bioenergy and a higher contribution from TravelCenters of America in part supported by a partial recovery from the US freight recession. Earnings growth is expected to be supported by structural cost reduction. bp continues to expect fuels margins to remain sensitive to the cost of supply and earnings delivery to remain sensitive to the relative strength of the US dollar.
- In products, bp expects broadly flat refining margins relative to 2024 and stronger underlying performance underpinned by the absence of the plant-wide power outage at Whiting refinery, and improvement plans across the portfolio. bp expects similar levels of refinery turnaround activity, with phasing of turnaround activity in 2025 heavily weighted towards the first half, with the highest impact in the second quarter.
- bp expects other businesses & corporate underlying annual charge to be around $1.0 billion for 2025. The charge may vary from quarter to quarter.

★ See glossary on **page 351**

Cash flow and debt information

	$ million		
	2024	2023	2022
Cash flow			
Operating cash flow★	**27,297**	32,039	40,932
Net cash used in investing activities	**(13,250)**	(14,872)	(13,713)
Net cash provided by (used in) financing activities	**(7,297)**	(13,359)	(28,021)
Cash and cash equivalents at end of year[a]	**39,269**	33,030	29,195
Capital expenditure★[b]	**(16,237)**	(16,253)	(16,330)
Divestment and other proceeds[c]	**4,224**	1,843	3,123
Debt			
Finance debt	**59,547**	51,954	46,944
Net debt★	**22,997**	20,912	21,422
Net debt including leases★	**34,909**	31,902	29,990
Finance debt ratio★ (%)	**43.2%**	37.8%	36.1%
Gearing★ (%)	**22.7%**	19.7%	20.5%
Gearing including leases★ (%)	**30.8%**	27.2%	26.5%

a 2024 includes $65 million of cash and cash equivalents classified as assets held for sale in the group balance sheet.
b An analysis of capital expenditure by segment and region is provided on page 312.
c Divestment proceeds are disposal proceeds as per the group cash flow statement. See below for more information on divestment and other proceeds.

Operating cash flow

Operating cash flow for the year ended 31 December 2024 was $27.3 billion, $4.7 billion lower than 2023. Compared with 2023, operating cash flows in 2024 primarily reflected lower profits from operations partly offset by working capital movements.

Movements in working capital★ favourably impacted cash flow in the year by $4.0 billion, including an adverse impact from the Gulf of America oil spill of $1.1 billion. Other working capital effects were principally a decrease in other current assets. bp actively manages its working capital balances to optimize and reduce volatility in cash flow.

Operating cash flow for the year ended 31 December 2023 was $32.0 billion, $8.9 billion lower than 2022. Compared with 2022, operating cash flows in 2023 primarily reflected lower realizations, refining margins and oil trading performance and the impact of portfolio changes.

Movements in working capital adversely impacted cash flow in 2023 by $3.3 billion, including an adverse impact from the Gulf of America oil spill of $1.2 billion. Other working capital effects were principally a decrease in other current liabilities, partly offset by decreases in inventory and other current assets.

Net cash used in investing activities

Net cash used in investing activities for the year ended 31 December 2024 decreased by $1.6 billion compared with 2023.

The decrease mainly reflected an increase in divestment proceeds and a net cash inflow from acquisitions, partly offset by an increase in expenditure on fixed assets.

Total capital expenditure for 2024 was $16.2 billion (2023 $16.3 billion), of which organic capital expenditure★ was $16.1 billion (2023 $15.0 billion). Inorganic capital expenditure for 2024 includes the cash acquired net of acquisition payments on completion of the bp Bunge Bioenergia and Lightsource bp acquisitions. Inorganic capital expenditure for 2023 includes $1.1 billion, net of adjustments, in respect of the TravelCenters of America acquisition. Sources of funding are fungible, but the majority of the group's funding requirements for new investment comes from cash generated by existing operations. bp expects capital expenditure of around $15 billion in 2025 and a range of $13-15 billion per annum from 2026 to 2027.

Total divestment and other proceeds for 2024 amounted to $4.2 billion, including $0.9 billion from the sale of receivables and $0.7 billion cash received, both relating to prior divestments, and $0.6 billion relating to the formation of Arcius Energy. Other proceeds for 2024 consist of $0.8 billion of proceeds from the sale of a non-controlling interest in the subsidiary that holds our 20% share in Trans Adriatic Pipeline AG (TAP) and $0.5 billion of proceeds from the sale of a 49% interest in a controlled affiliate holding certain midstream assets offshore US.

Total divestment and other proceeds for 2023 amounted to $1.8 billion, including $0.5 billion relating to the sale of the upstream business in Algeria and $0.3 billion relating to the disposal of bp's interest in the bp-Husky Toledo refinery. Other proceeds for 2023 consist of $0.5 billion of proceeds from the sale of a 49% interest in a controlled affiliate holding certain midstream assets onshore US.

As at 31 December 2024, $22.0 billion of proceeds were received against our target of $25 billion of divestment and other proceeds between the second half of 2020 and 2025. bp expects divestment and other proceeds to be around $3 billion in 2025.

Net cash provided by (used in) financing activities

Net cash used in financing activities for the year ended 31 December 2024 was $7.3 billion, compared with $13.4 billion in 2023. Compared with 2023, financing cash flows in 2024 primarily reflected higher receipts from the issue of perpetual hybrid bonds and higher net proceeds from the issuance and repayment of finance debt.

In 2024, 1,238 million of ordinary shares (2023 1,263 million) were repurchased for cancellation for a total cost of $7.1 billion (2023 $7.9 billion), including transaction costs of $38 million (2023 $43 million).

Total dividends paid to shareholders in 2024 were 30.540 cents per share, 2.78 cents higher than 2023. This amounted to total dividends paid to shareholders of $5.0 billion in 2024 (2023 $4.8 billion). The board decided not to offer a scrip dividend alternative in respect of the 2024 and 2023 dividends.

Debt

Finance debt at the end of 2024 increased by $7.6 billion from the end of 2023 primarily reflecting net long-term debt issuances. The finance debt ratio at the end of 2024 increased to 43.2% from 37.8% at the end of 2023.

Net debt at the end of 2024 increased by $2.1 billion from the 2023 year-end position. Gearing at the end of 2024 increased to 22.7% from 19.7% at the end of 2023. The increase in net debt and gearing primarily reflects the net debt acquired from the completion of the bp Bunge Bioenergia and Lightsource bp transactions partially offset by the issuance of perpetual hybrid securities. Net debt and gearing are non-IFRS measures. See Financial statements – **Notes 26** and **27** for further information on finance debt and net debt.

For information on financing the group's activities see Financial statements – **Note 29** and Liquidity and capital resources on **page 316**.

Group reserves and production[a]

	2024	2023	2022
Estimated net proved reserves (net of royalties)			
Liquids (mmb)	**3,699**	3,747	3,997
Natural gas (bcf)	**14,786**	17,471	18,481
Total hydrocarbons[b] (mmboe)	**6,248**	6,759	7,183
Of which:			
Equity-accounted entities[b]	**1,377**	1,437	1,381
Production (net of royalties)			
Liquids (mb/d)	**1,166**	1,115	1,214
Natural gas (mmcf/d)	**6,914**	6,944	7,101
Total hydrocarbons[c] (mboe/d)	**2,358**	2,313	2,438
Of which:			
Subsidiaries	**2,008**	1,967	2,000
Equity-accounted entities[c]	**350**	345	439

a Because of rounding, some totals may not agree exactly with the sum of their component parts.
b See Supplementary information on oil and natural gas on page 223 for further information. See page 322 for more information on bp's oil and gas reserves including the impact of events occurring after the end of the reporting period.
c 2022 includes bp's share of Rosneft and Russia joint ventures (193mboe/d). See Oil and gas disclosures for the group on page 324 for further information.

Total hydrocarbon proved reserves at 31 December 2024, on an oil equivalent basis, including equity-accounted entities, decreased by 8% compared with 31 December 2023 (8% decrease for subsidiaries and 4% decrease for equity-accounted entities). Natural gas decreased by 15% (19% decrease for subsidiaries and 5% increase for equity-accounted entities).

There was a net decrease from acquisitions and disposals of 72mmboe within our US, Trinidad and North Africa subsidiaries.

Total hydrocarbon production for the group was 2.0% higher compared with 2023. The increase comprised a 2.1% increase (5.6% increase for liquids and 0.6% decrease for gas) for subsidiaries and a 1.4% increase (1.3% increase for liquids and 2.0% increase for gas) for equity-accounted entities.

Gas & low carbon energy

Gas & low carbon energy segment comprises our gas & low carbon businesses. Our gas business includes regions[a] with upstream activities that predominantly produce natural gas, integrated gas and power, and gas trading. Our low carbon business includes solar, offshore and onshore wind, hydrogen and CCS, and power trading. Power trading and marketing includes trading of both renewable and non-renewable power.

Financial and operating performance

	$ million		
	2024	2023	2022[b]
Sales and other operating revenues[c]	**32,628**	50,297	56,255
Profit before interest and tax	**3,569**	14,081	14,688
Inventory holding (gains) losses★	**—**	(1)	8
RC profit before interest and tax	**3,569**	14,080	14,696
Net (favourable) adverse impact of adjusting items★[d]	**3,234**	(5,358)	1,367
Underlying RC profit before interest and tax★	**6,803**	8,722	16,063
Taxation on an underlying RC basis	**(2,137)**	(2,730)	(4,367)
Underlying RC profit before interest	**4,666**	5,992	11,696
Depreciation, depletion and amortization	**4,835**	5,680	5,008
Exploration write-offs	**222**	362	2
Adjusted EBITDA★[e]	**11,860**	14,764	21,073
Capital expenditure★			
Gas	**3,615**	3,025	3,227
Low carbon energy	**1,596**	1,256	1,024
	5,211	4,281	4,251

a The AGT and Middle East regions have been further subdivided by asset to allow reporting in either gas & low carbon or oil production & operations as appropriate.
b 2022 includes bp Bunge Bioenergia. From the first quarter of 2023, bp Bunge Bioenergia is reported within customers & products.
c Includes sales to other segments.
d See page 314 for information on the cumulative impact of FVAEs.
e A reconciliation to RC profit before interest and tax is provided on page 362.

Financial results

Sales and other operating revenues for 2024 are lower than 2023 due to materially lower trading results, lower gas prices and lower volumes.

RC profit before interest and tax for 2024 was $3,569 million compared with $14,080 million for 2023.

Items which bp has classified as adjusting for 2024 had a net adverse impact of $3,234 million including adverse fair value accounting effects (FVAEs)★ of $1,550 million, relative to management's view of performance, net impairment charges of $3,004 million, partly offset by a gain of $1,006 million as a result of remeasurement of our previously existing interest and related assets on the step-acquisition of Lightsource bp (LSbp).

After adjusting RC profit for the net impact of items which bp has classified as adjusting, underlying RC profit before interest and tax for 2024 was $6,803 million, compared with $8,722 million for 2023. The decrease reflects a lower gas marketing and trading result, lower realizations and lower production partly offset by a lower depreciation, depletion and amortization charge and lower exploration write-offs.

Items which bp has classified as adjusting for 2023 had a net favourable impact of $5,358 million including favourable FVAEs of $8,859 million, relative to management's view of performance, partially offset by a net impairment charges.

See Financial statements – **Note 4** and **Note 16** for further information on net impairment charges.

Operational update

Reported production for 2024 was 888mboe/d, 4.4% lower than the same period in 2023. Underlying production★ for the full year was 2.8% lower, mainly due to base decline in Egypt, partially offset by major projects★ ramp-up.

Renewables pipeline★ at the end of the year was 60.6GW (bp net), including 38.7GW of LSbp's pipeline. The renewables pipeline showed a net increase of 2.3GW during the year as a result of the LSbp acquisition (20.5GW), offset by reductions as a result of high-grading and focus on proposed hydrogen projects and the US solar business.

In renewables by the end of 2024 we had cumulatively brought 8.2GW (bp net) developed renewables to FID★.

Strategic progress

Gas

In Indonesia, we announced the final investment decision on the $7 billion Tangguh Ubadari, carbon capture, utilization and storage (CCUS) Compression project (UCC), which has the potential to unlock around 3 trillion cubic feet of additional gas resources in Indonesia. Tangguh CCUS aims to be the first CCUS project developed at scale in Indonesia.

In Trinidad, we have made progress on our growth projects and high graded our portfolio:

- In June we sanctioned the Coconut project and in August we agreed to partner with EOG Resources Trinidad Limited to develop the Coconut gas field.
- In July, together with our partner NGC, we were awarded an exploration and production licence by the Bolivarian Republic of Venezuela for the development of the cross-border Cocuina gas discovery.
- In December we completed the sale of four mature offshore gas fields and associated production facilities to Perenco T&T.

In Egypt, we completed the formation of a new joint venture, Arcius Energy (51% bp, 49% XRG). The JV will initially operate in Egypt, and includes interests assigned by bp across two development concessions, as well as exploration agreements.

In December, we completed a sale of a non-controlling stake in bp Pipelines TAP Limited, the bp subsidiary that holds a 20% share in Trans Adriatic Pipeline AG (TAP), to Apollo-managed funds.

In January 2025 we announced that we have begun flowing gas from wells at the Greater Tortue Ahmeyim (GTA) project off the coast of West Africa. Once fully commissioned, it is expected to produce 2.4Mtpa of LNG.

In February 2025 we signed an agreement with ONGC as the technical services provider for the largest offshore oil field in India, which accounts for around 25% of the country's oil production.

LNG portfolio

In April bp and Korea Gas Corporation (KOGAS) announced the signing of a long-term agreement to supply up to 9.8Mt of LNG over 11 years on a delivered ex-ship (DES) basis from 2026. This builds on the existing long-term sale to KOGAS and further adds to bp's global LNG market presence in key demand regions.

In July bp confirmed it would take 10% interest in the new ADNOC-operated LNG facility in Abu Dhabi (Ruwais LNG), further deepening bp's longstanding partnership with ADNOC. The project has planned total LNG production capacity of 9.6mmtpa.

bp and its partners concluded the restructured ownership and commercial framework of Atlantic LNG in Trinidad and Tobago effective 1 October, which allows for an intensified focus on operational efficiency and reliability and provides the certainty required for sanctioning the next wave of upstream gas projects.

See Oil and gas disclosures for the group on **page 318** for more information on oil and gas operations in the regions.

Low carbon energy

In 2024 we have initiated a significant portfolio reset of low carbon energy businesses and we are making strong progress on the programmes that are driving focus and reducing costs.[a]

Hydrogen and carbon capture and storage

In 2024 we have refocused our H2CCS business by reducing the number of projects from 30 to five to seven high-quality hydrogen/CCS projects this decade, four of which have taken FID in 2024:

- In September together with our partner Iberdrola, we sanctioned construction of a 25MW green hydrogen★ project at bp's Castellón refinery in Spain which is expected to be operational in the second half of 2026.
- In December financial close was reached for two major projects in Teesside, UK: the Northern Endurance Partnership (NEP) carbon capture and storage project and the Net Zero Teesside Power (NZT Power) project.
- We also announced in December the final investment decision for 100MW Lingen Green Hydrogen project (see case study, right).

Renewables and power

Offshore wind

We have changed our model for offshore wind – delivering with partners and with external financing that will be capital-light for bp and improve our equity returns.

In December we announced our agreement with JERA Co., Inc. to combine our global offshore wind businesses to form a new standalone, equally-owned joint venture JERA Nex bp (see case study, right).

In December the Japanese government selected a consortium involving bp, Tokyo Gas, Marubeni Corporation, Kansai Electric Power and Marutaka Corporation to build a 450MW offshore wind farm.

Onshore renewables

In October we completed the acquisition of the remaining 50.03% interest in LSbp, one of the world's leading developers and operators of utility-scale solar and battery storage assets operators. LSbp has developed 12GW to date including 3GW of projects to FID in 2024. In 2024 it also constructed over 2GW with total cost under budget as well as significantly developing battery energy storage systems capabilities and footprint. In February 2025 we announced our intention to bring a strategic partner into the business.

In September we announced our plans to sell our existing US onshore wind energy business, bp Wind Energy (10 operating wind assets, net total generating capacity 1.3GW) and aim to bring together the development of onshore renewable power projects through Lightsource bp.

Power trading

In August we announced we have completed the acquisition of GETEC ENERGIE GmbH, a leading independent supplier of energy to commercial and industrial customers in Germany. This deal will accelerate the growth of bp's European gas and power presence.

LiDAR buoys help inform offshore wind farm development, Liverpool, UK

Partnering for offshore wind

bp and JERA Co., Inc., Japan's largest power generation company, have agreed to set up a new 50:50 joint venture, JERA Nex bp, that will become one of the largest global offshore wind developers, owners and operators. The joint venture aims to create a strategic platform for growth by combining a balanced mix of operating assets and development projects with total 13GW potential net generating capacity. Subject to regulatory and other approvals, we aim to complete the formation of JERA Nex bp by the end of the third quarter of 2025.

bp's Lingen refinery, Germany

Green hydrogen in Germany

In December 2024 bp announced the final investment decision for its 100MW Lingen Green Hydrogen (LGH2) project in Germany. It is expected to be bp's largest industrial green hydrogen plant and the first that we will fully own and operate. The project is expected to produce around 11,000 tonnes of green hydrogen annually, with commissioning expected in 2027.

a From 2025 we intend to report our biogas business as part of the gas & low carbon energy segment.

Gas & low carbon energy continued

Estimated net proved reserves and production[a] (net of royalties)

	2024	2023	2022
Estimated net proved reserves (net of royalties)			
Crude oil[b] (mmb)	**113**	128	151
Natural gas liquids (mmb)	**1**	1	9
Total liquids★[c]	**115**	129	160
Natural gas[c] (bcf)	**6,965**	8,635	9,708
Total hydrocarbons★[c] (mmboe)	**1,316**	1,618	1,834
Of which equity-accounted entities[d]:			
Liquids (mmb)	**1**	–	–
Natural gas (bcf)	**196**	–	–
Total hydrocarbons (mmboe)	**35**	–	–
Production (net of royalties)			
Crude oil[be] (mb/d)	**88**	96	103
Natural gas liquids (mb/d)	**8**	9	15
Total liquids (mb/d)	**96**	105	118
Natural gas (mmcf/d)	**4,596**	4,778	4,866
Total hydrocarbons (mboe/d)	**888**	929	957
Of which equity-accounted entities[f]:			
Liquids (mb/d)	**2**	2	2
Natural gas (mmcf/d)	**9**	–	–
Total hydrocarbons (mboe/d)	**4**	2	2
Average realizations★[g]			
Liquids ($/bbl)	**75.37**	77.03	89.86
Natural gas ($/mcf)	**5.90**	6.13	8.91
Total hydrocarbons ($/boe)	**38.57**	40.21	56.34

a Because of rounding, some totals may not agree exactly with the sum of their component parts.
b Includes condensate and bitumen.
c Includes 1.7 million barrels of total liquids (2.2 million barrels at 31 December 2023 and 3 million barrels at 31 December 2022) and 219 billion cubic feet of natural gas (430 billion cubic feet at 31 December 2023 and 547 billion cubic feet at 31 December 2022) in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
d bp's share of reserves of equity-accounted entities in the gas & low carbon energy segment.
e 2023 restated, 4mb/d previously reported in NGLs.
f bp's share of production of equity-accounted entities in the gas & low carbon energy segment.
g Realizations are based on sales by consolidated subsidiaries only – this excludes equity-accounted entities.

Renewables

	2024	2023	2022
Renewables (bp net, GW)			
Installed renewables capacity★	**4.0**	2.7	2.2
Developed renewables to FID★	**8.2**	6.2	5.8
Renewables pipeline	**60.6**	58.3	37.2
of which by geographical area:			
Renewables pipeline – Americas	**21.2**	18.8	17.0
Renewables pipeline – Asia Pacific	**15.1**	21.3	11.8
Renewables pipeline – Europe	**23.6**	14.6	8.3
Renewables pipeline – Other	**0.7**	3.5	0.1
of which by technology:			
Renewables pipeline – offshore wind	**9.7**	9.3	5.2
Renewables pipeline – onshore wind	**6.6**	12.7	6.3
Renewables pipeline – solar	**44.3**	36.3	25.7
Total developed renewables to FID and renewables pipeline	**68.8**	64.5	43.0

Tangguh LNG facility, Papua Barat, Indonesia

Natural gas in Indonesia

bp and its partners approved the $7 billion Tangguh UCC project in Papua Barat, Indonesia. This initiative will help unlock around 3 trillion cubic feet of natural gas and help meet growing energy demand in Asia. Through the use of CCUS for enhanced gas recovery, the project has the potential to sequester around 15MtCO_2 in its initial phase, reducing overall CO_2 emissions intensity from operations at Tangguh.

The potential site of NZT Power, UK

Teesside carbon capture milestone

In December 2024, bp and partners reached financial close on the Net Zero Teesside Power (NZT Power) and Northern Endurance Partnership (NEP) projects. NZT Power aims to be one of the world's first gas-fired power stations with carbon capture, and could generate up to 742MW of flexible, dispatchable low carbon power and could capture up to 2MtCO_2 annually. NEP will develop the infrastructure to transport and store up to an initial 4MtCO_2 annually from three Teesside-based carbon capture projects within the East Coast Cluster, with the ability to expand in the future. Both projects are expected to support thousands of jobs and help advance the UK's journey to net zero.

Oil production & operations

Oil production & operations segment comprises regions[a] with upstream activities that predominantly produce crude oil, including bpx energy.

Financial and operating performance

	$ million		
	2024	2023	2022
Sales and other operating revenues[b]	**25,637**	24,904	33,193
Profit before interest and tax	**10,780**	11,191	19,714
Inventory holding (gains) losses★	**9**	—	7
RC profit before interest and tax	**10,789**	11,191	19,721
Net (favourable) adverse impact of adjusting items★	**1,148**	1,590	503
Underlying RC profit before interest and tax★	**11,937**	12,781	20,224
Taxation on an underlying RC basis	**(5,165)**	(5,998)	(9,143)
Underlying RC profit before interest	**6,772**	6,783	11,081
Depreciation, depletion and amortization	**6,797**	5,692	5,564
Exploration write-offs	**544**	384	383
Adjusted EBITDA★[c]	**19,278**	18,857	26,171
Capital expenditure★	**6,198**	6,278	5,278

a The AGT and Middle East regions have been further subdivided by asset to allow reporting in either gas & low carbon or oil production & operations as appropriate.
b Includes sales to other segments.
c A reconciliation to RC profit before interest and tax is provided on page 362.

bpx energy, Permian Basin processing facility in Texas, US

Growth in the Permian

In 2024, bp's US onshore oil and gas business, bpx energy, achieved its 30-40% growth target, set for 2025, a year early. And it brought online Checkmate, its third central processing facility in the Permian Basin in April. The electrified facility is designed to support further production growth for bpx energy in the basin.

Financial results

Sales and other operating revenues for 2024 were higher than 2023 mainly due to higher volumes partially offset by lower realizations.

RC profit before interest and tax for 2024 was $10,789 million compared with $11,191 million for 2023.

Adjusting items for 2024 had a net adverse impact of $1,148 million principally relating to net impairment charges. See Financial statements – **Note 4** and **Note 16** for further information on net impairment charges.

After adjusting RC profit for the net adverse impact of adjusting items, underlying RC profit before interest and tax for 2024 was $11,937 million, compared with $12,781 million for 2023. The lower profit reflects lower realizations, and the impact of increased depreciation charges and higher exploration write-offs, partly offset by higher volumes.

Adjusting items for 2023 had a net adverse impact of $1,590 million mainly relating to net impairment charges. See Financial statements – **Note 4** and **Note 16** for further information on net impairment charges.

Operational update

Reported production for 2024 was 1,470mboe/d, 6.3% higher than the same period of 2023. Underlying production★ for the year was 6.2% higher compared with the same period of 2023 reflecting bpx energy performance and major projects★ partly offset by base performance.

Strategic progress

- Aker BP announced oil production had started from the Tyrving field, which is part of the life extension of the Alvheim field.
- ACG joint venture partners announced the signing of an addendum to the existing PSA which enables the parties to progress the exploration, appraisal, development of and production from the non-associated natural gas reservoirs of the ACG field (bp operator with 30.37% equity).
- Azule Energy completed the acquisition of a 42.5% interest in exploration block 2914A (PEL85), Orange Basin, offshore Namibia.
- bp sanctioned the Atlantis Drill Center Expansion in the Gulf of America (bp share 56%).
- Aker BP was awarded interests in 19 licences (of which it will operate 16) in the North Sea and Norwegian Sea (bp 15.9%).
- bp was awarded a licence for two blocks in the central North Sea, consolidating our position around our Eastern Trough Area Project (ETAP) central processing facility.
- The Production Sharing Contract for the Tupinamba block in Brazil was executed (bp 100%).

See Oil and gas disclosures for the group on **page 318** for more information on oil and gas operations in the regions.

★ See glossary on **page 351**

Oil production & operations continued

Estimated net proved reserves and production[a] (net of royalties)

	2024	2023	2022
Estimated net proved reserves (net of royalties)			
Crude oil[b] (mmb)	**3,112**	3,193	3,380
Natural gas liquids (mmb)	**472**	426	457
Total liquids	**3,584**	3,618	3,836
Natural gas (bcf)	**7,821**	8,836	8,774
Total hydrocarbons ★ (mmboe)	**4,932**	5,142	5,349
Of which equity-accounted entities[c]:			
Liquids (mmb)	**917**	1,001	968
Natural gas (bcf)	**2,467**	2,527	2,394
Total hydrocarbons (mmboe)	**1,342**	1,437	1,381
Production (net of royalties)			
Crude oil[b] (mb/d)	**953**	910	866
Natural gas liquids (mb/d)	**117**	100	86
Total liquids (mb/d)	**1,070**	1,010	952
Natural gas (mmcf/d)	**2,318**	2,165	1,998
Total hydrocarbons (mboe/d)	**1,470**	1,383	1,297
Of which equity-accounted entities[d]:			
Liquids (mb/d)	**272**	269	176
Natural gas (mmcf/d)	**431**	432	436
Total hydrocarbons (mboe/d)	**346**	343	251
Average realizations ★[e]			
Liquids ($/bbl)	**69.85**	72.09	89.62
Natural gas ($/mcf)	**2.55**	4.17	10.46
Total hydrocarbons ($/boe)	**53.96**	58.34	82.23

a Because of rounding, some totals may not agree exactly with the sum of their component parts.
b Includes condensate and bitumen.
c bp's share of reserves of equity-accounted entities in the oil production & operations segment. During 2024 gas operations in Angola, Argentina, Bolivia, Mexico and Norway were conducted through equity-accounted entities.
d bp's share of production of equity-accounted entities in the oil production & operations segment. 2022 includes bp's share of production of Russia joint ventures.
e Realizations are based on sales by consolidated subsidiaries only – this excludes equity-accounted entities.

Expansion in the Gulf

We took a final investment decision on the Kaskida project in the US Gulf of America in July. The floating production platform is expected to have a capacity of 80,000 barrels of oil per day from six wells in its first phase. Kaskida will be bp's sixth hub in the Gulf of America and production is expected to start in 2029.


ACE platform in the Caspian Sea, Azerbaijan

Progress in Azerbaijan

In April we started up oil production from the Azeri Central East (ACE) platform, as part of the Azeri-Chirag-Gunashli development in the Caspian Sea. ACE is bp's first fully remotely operated offshore platform. Its innovative engineering helps automate labour-intensive processes, supporting safer and more efficient operations as well as helping lower operational emissions.

Redevelopment of Kirkuk

On 25 February 2025 bp reached agreement on all contractual terms with the government of the Republic of Iraq to invest in several giant oil fields in Kirkuk providing for the rehabilitation and redevelopment of the fields, spanning oil, gas, power and water with potential for investment in exploration. The agreement is subject to final governmental ratification.

Customers & products

Customers & products segment comprises our customer-focused businesses, which include 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.

Financial and operating performance

	$ million		
	2024	2023	2022
Sales and other operating revenues[a]	**155,401**	160,215	188,623
Profit (loss) before interest and tax	**(2,039)**	2,993	10,235
Inventory holding (gains) losses★	**479**	1,237	(1,366)
Replacement cost (RC) profit (loss) before interest and tax	**(1,560)**	4,230	8,869
Net (favourable) adverse impact of adjusting items★[b]	**4,077**	2,183	1,920
Underlying RC profit before interest and tax★	**2,517**	6,413	10,789
Of which:			
customers – convenience & mobility	**2,584**	2,644	2,966
Castrol – included in customers	***831***	*730*	*700*
products – refining & trading	**(67)**	3,769	7,823
Taxation on an underlying RC basis	**(452)**	(1,454)	(2,308)
Underlying RC profit before interest	**2,065**	4,959	8,481
Depreciation, depletion and amortization	**3,957**	3,548	2,870
Of which:			
customers – convenience & mobility	**2,135**	1,736	1,286
Castrol – included in customers	***176***	*167*	*153*
products – refining & trading	**1,822**	1,812	1,584
Adjusted EBITDA★[c]	**6,474**	9,961	13,659
Of which:			
customers – convenience & mobility	**4,719**	4,380	4,252
Castrol – included in customers	***1,007***	*897*	*853*
products – refining & trading	**1,755**	5,581	9,407
Capital expenditure★	**4,420**	5,253	6,252
Of which:			
customers – convenience & mobility	**2,059**	3,135	1,779
Castrol – included in customers	***227***	*262*	*235*
products – refining & trading	**2,361**	2,118	4,473

a Includes sales to other segments.
b See page 314 for information on the cumulative impact of FVAEs.
c A reconciliation to RC profit before interest and tax by business is provided on page 327.


bp bioenergy, Brazil

Scaling up biofuels

We took full ownership of bp bioenergy, one of Brazil's leading biofuels-producing companies, in October. The acquisition means bp now has the capacity to produce around 50,000 barrels a day of ethanol equivalent from sugar cane through the business's 11 agro-industrial units across five Brazilian states.

Epic expansion

In 2024 we launched our own line of private label consumer-packaged products in the US – *epic goods*. Initially featuring a few products, the range expanded to over 50 SKUs by the end of 2024. *epic goods* is available in 1,500 locations across our *ampm*, TravelCenters of America, *Thorntons* brands and many of our franchised locations, offering a range of nuts, juices and bottled water.

Financial results

Sales and other operating revenues in 2024 were lower than in 2023, mainly due to lower product prices.

RC loss before interest and tax for 2024 was $1,560 million, compared with a profit of $4,230 million for 2023.

Items which bp has classified as adjusting for 2024 had a net adverse impact of $4,077 million (including adverse fair value accounting effects of $81 million – relative to management's view of performance), of which $1,660 million related to impairments of assets, which included an impairment of the Gelsenkirchen refinery and $1,267 million related to loss on disposal, mainly related to the Türkiye grounds fuels business disposal. See Financial statements – **Note 4** for further information on disposals and impairments.

After adjusting RC loss for the net adverse impact of items, which bp classified as adjusting, underlying RC profit before interest and tax (underlying result) was $2,517 million, compared with $6,413 million for 2023. The result was significantly lower, primarily reflecting the impact of lower refining margins and a lower oil trading contribution.

Items which bp has classified as adjusting for 2023 had a net adverse impact of $2,183 million (including adverse fair value accounting effects of $86 million – relative to management's view of performance), of which $1,614 million related to impairment of assets, which included an impairment of the Gelsenkirchen refinery.

Customers – the convenience and mobility underlying result for 2024 was lower than 2023. The 2024 underlying result benefited from a continued stronger performance in *Castrol*, driven by higher unit margins and volumes and lower costs. In addition, the continued momentum in EV charging, convenience and retail fuels margins was more than offset by a significantly weaker European midstream performance driven by biofuels margins. The contribution of TravelCenters of America continues to be impacted by the US freight recession.

Products – the underlying result for 2024 was significantly lower than 2023. In refining, the result was lower, primarily due to lower realized refining margins and the first quarter plant-wide power outage at the Whiting refinery, partly offset by a lower impact from turnaround activity. The contribution from oil trading was also significantly lower than 2023.

Operational update

bp-operated refining availability★ for 2024 was 94.3%, lower compared with 96.1% in 2023, mainly due to the first quarter Whiting refinery power outage.

Strategic progress

Convenience & retail fuels

In February 2025, bp completed the acquisition of fuel and convenience retailer, X Convenience, expanding its network with the addition of 49 sites in South and Western Australia.

Strategic convenience sites★ grew to 2,950, an increase of more than 100 sites compared to 2023.

In support of high-grading our retail fuels and convenience portfolio, in October 2024, bp completed the sale of Türkiye ground fuels business to Petrol Ofisi, including the group's interest in three joint venture terminals in Türkiye and in November 2024, announced its intention to sell its mobility and convenience and *bp pulse* businesses in the Netherlands, with completion of the sale by the end of 2025.

In addition:

- In October 2024, bp announced the launch of earnify, a loyalty programme designed to provide customers with a seamless, integrated and rewarding experience, including exclusive discounts on retail store products and fuel purchases in around 5,500 bp, Amoco and *ampm* branded stores across the US.

EV charging

EV charging continued to show strong momentum. Energy sold and EV charge points★ installed in the year grew by around 75% and 35% respectively, compared to 2023, with charge points now around 39,100.

bp continued to advance its future network growth:

- In July 2024 bp signed a deal with Simon Property Group to install and operate up to 900 ultra-fast charging★ bays at up to 75 sites across the US, with initial sites expected to open to the public in early 2026.
- In September 2024, bp signed a deal with LAZ parking in the US, to roll-out ultra-fast charging hubs in 20 cities.

In addition:

- In March 2024 bp acquired the freehold of one of the largest truck stops in Europe, Ashford International Truckstop in Kent. The acquisition presents bp with the opportunity to help meet the comprehensive needs of UK and European HGV operators transitioning to EVs.
- In April, bp opened its first *bp pulse* branded *Gigahub* in Houston, Texas, with 24 ultra-fast★ charge points, building momentum in our US charging business offering.

Castrol

Castrol continued to diversify beyond its core lubricants and fluids business under a new ‘Onward, Upward, Forward’ strategy. Establishing a strong presence as a Data Center liquid cooling solution provider with continuous expansion to cover the full range of technology. Strong collaboration with leading AI Server/Chips players such as Supermicro and Intel.

In addition:

- In June 2024 *Castrol* announced an investment in Gogoro Inc., a global technology leader in two-wheeler battery-swapping ecosystems that enable smart mobility solutions for cities.
- *Castrol* continued to grow its independent branded workshops, adding around 4,000 workshops in 2024, compared to 2023, with workshops now over 38,000 in total.

As announced in February 2025, bp is carrying out a strategic review of its *Castrol* business with the intention of accelerating *Castrol*’s next phase of value creation.

Audi bp partnership

Fuelling innovation

In July we announced a new strategic partnership with Audi for Formula 1. Through the partnership, we plan to develop the FIA-specified advanced sustainable fuel[a] for Audi's 2026 entry into Formula 1 and through *Castrol*, we plan to develop lubricants and EV fluids for Audi's V6 turbo engine and electric motor and battery. The collaboration also includes long-term sponsorship, making bp the first official partner of Audi's future Formula 1 factory team.

Charging ahead

ADAC, Germany’s leading automobile association with over 20 million members, announced *Aral* pulse, bp’s EV charging brand in Germany, as their new exclusive EV charging partner from 1 August. The partnership supports *Aral* pulse’s aim to expand its existing network. Additionally, bp opened our first standalone *Aral* EV charging *Gigahub* in Mönchengladbach in November 2024, featuring 28 charge points and a 24/7 smart store.

a FIA advanced sustainable fuel must achieve at least 65% greenhouse gas emissions savings relative to fossil-derived petrol produced at installations operating since 2021. See 2026 F1 Technical Regulations for details.

Bioenergy

bp's Archaea Energy started up nine renewable natural gas (RNG) landfill plants in 2024, with a total capacity of more than 10 million mmBtu per annum. This includes one of its largest Archaea Modular Design plants in Shawnee, Kansas in April. Located next to a large private owned landfill, the Shawnee plant captures landfill gas and converts it to RNG with a total capacity of 9,600 standard cubic feet. In February 2025 bp announced its intention to move its biogas business to the gas & low carbon energy segment.

In biofuels, bp took full ownership of bp bioenergy in Brazil in October 2024. In January 2025, bp announced the decision to rephase its biofuels project in Kwinana, Australia, with the objective of improving capital productivity. In addition, as announced in February 2025, bp will continue to assess options for investment in standalone biofuels plants, co-located with our existing refineries with the potential to move one project to FID by 2027. However, we will only proceed when project economics are supportive.

In addition:

- In April 2024, bp launched its new hydrotreated vegetable oil (HVO) bioenergy brand, marketed as bp bioenergy HVO, and commencing with roll-out at sites across the UK and the Netherlands.
- During the fourth quarter bp continued to progress its strategic plans to access feedstock for biofuels, announcing a 10-year agreement with agri-food group MIGASA for the supply of up to 40,000 tonnes per year of vegetable oil waste, and announcing a collaboration with Corteva, with the intent of forming a JV, on novel feedstocks.

Refining

bp continued to high grade its refining portfolio, announcing in February 2025 bp's intention to market its Ruhr Oel GmbH – BP Gelsenkirchen operation in Germany for potential sale, including its refinery in Gelsenkirchen and DHC Solvent Chemie GmbH in Mülheim an der Ruhr. This is in addition to bp's plans, announced in March 2024, to transform the Gelsenkirchen refinery site by the end of the decade. The plans include simplification of the site to improve its competitiveness, including a controlled reduction in total production capacity from 2025 and increased production of lower-emission fuels using co-processing.

In addition:

- On 19 June 2024 bp completed the sale of its 8.3% shareholding in Channel Infrastructure, which owns and operates New Zealand's Marsden Point fuel import terminal. Our long-term terminal storage agreements with Channel Infrastructure to meet bp's foreseeable import and supply requirements are unaffected by the sale of these shares.
- On 1 December 2024, bp completed the sale of its 50% ownership in the SAPREF refinery to the South African state-owned entity, Central Energy Fund SOC Ltd.

★ See glossary on **page 351**

Other businesses & corporate

Other businesses & corporate comprises technology, bp ventures, our corporate activities & functions and any residual costs of the Gulf of America oil spill. From the first quarter 2022 the results of Rosneft, previously reported as a separate segment, are also included in other businesses & corporate. For more information see Financial statements – Note 1 Significant accounting policies, judgements, estimates and assumptions – Investment in Rosneft.

Financial and operating performance

	$ million		
	2024	2023	2022
Sales and other operating revenues[a]	**2,290**	2,657	2,299
Profit (loss) before interest and tax	**(988)**	(903)	(26,737)
Inventory holding (gains) losses★	**—**	—	—
Replacement cost (RC) profit (loss) before interest and tax	**(988)**	(903)	(26,737)
Net (favourable) adverse impact of adjusting items★[b]	**380**	37	25,566
Underlying RC profit (loss) before interest and tax★	**(608)**	(866)	(1,171)
Taxation on an underlying RC basis	**292**	322	439
Underlying RC profit (loss) before interest	**(316)**	(544)	(732)
Depreciation, depletion and amortization	**1,033**	1,008	876
Capital expenditure★	**408**	441	549

a Includes sales to other segments.
b See page 314 for information on the cumulative impact of FVAEs.

Financial results

RC loss before interest and tax for 2024 was $988 million, compared with $903 million for 2023.

Adjusting items for 2024 had a net adverse impact of $380 million. Adjusting items include impacts of fair value accounting effects, which had an adverse impact of $221 million.

Adjusting items for 2023 had a net adverse impact of $37 million. Adjusting items include impacts of fair value accounting effects, which had a favourable impact of $630 million. Adjusting items also include impacts of environmental charges, which had an adverse impact of $604 million.

After adjusting RC loss for the adjusting items, underlying RC loss before interest and tax for 2024 was $608 million, compared with a loss of $866 million for 2023, mainly reflecting increased interest income.

Strategic progress

We continued to invest in a portfolio of technology businesses, which we see as having the potential for high growth, through bp ventures. Strategically significant investments made through 2024 include:

- In May bp ventures announced the investment of $10 million in Hysata to expand the production of its high efficiency electrolyser technology.
- In December, bp invested in Snowfox Discovery Ltd alongside co-investors Rio Tinto and Oxford Science Enterprises. Snowfox Ltd is a natural hydrogen exploration company, whose mission is to unlock the potential of natural hydrogen to contribute to a net zero future.
- In December, bp ventures announced an investment into Oxford Flow alongside Energy Impact Partners. Oxford Flow engineers and manufactures unique valve technology designed to be more reliable and cost-effective.
- In December, bp ventures invested in India's leading intercity bus platform, Zingbus, to scale operations and work to electrify India's intercity bus routes. Zingbus' platform is designed to make intercity travel more affordable, accessible and reliable.

Other businesses & corporate excluding Rosneft

	$ million		
	2024	2023	2022
Profit (loss) before interest and tax	**(988)**	(903)	(2,704)
Inventory holding (gains) losses	**–**	–	–
Replacement cost (RC) profit (loss) before interest and tax	**(988)**	(903)	(2,704)
Net (favourable) adverse impact of adjusting items	**380**	37	1,533
Underlying RC profit (loss) before interest and tax	**(608)**	(866)	(1,171)
Taxation on an underlying RC basis	**292**	322	439
Underlying RC profit (loss) before interest	**(316)**	(544)	(732)

Rosneft

	$ million		
	2024	2023	2022
Profit (loss) before interest and tax	**–**	–	(24,033)
Inventory holding (gains) losses	**–**	–	–
Replacement cost (RC) profit (loss) before interest and tax	**–**	–	(24,033)
Net (favourable) adverse impact of adjusting items	**–**	–	24,033
Underlying RC profit (loss) before interest and tax	**–**	–	–
Taxation on an underlying RC basis	**–**	–	–
Underlying RC profit (loss) before interest	**–**	–	–

	2024	2023	2022
Estimated net proved reserves (net of royalties) (bp share)			
Crude oil[a] (mmb)	**–**	–	–
Natural gas liquids (mmb)	**–**	–	–
Total liquids★	**–**	–	–
Natural gas (bcf)	**–**	–	–
Total hydrocarbons★ (mmboe)	**–**	–	–
Production[b] (net of royalties)			
Crude oil[a] (mb/d)	**–**	–	144
Natural gas liquids (mb/d)	**–**	–	–
Total liquids (mb/d)	**–**	–	144
Natural gas (mmcf/d)	**–**	–	238
Total hydrocarbons (mboe/d)	**–**	–	185

a Includes condensate.
b 2022 reflects bp's estimated share of Rosneft production for the period 1 January to 27 February only. The estimated share of production for that period has been averaged over the full year.

★ See glossary on **page 351**

Sustainability at bp

Our sustainability frame underpins the delivery of our strategy. It focuses on three areas – getting to net zero, improving people's lives and caring for our planet.

In February 2025, as part of our strategy reset, we announced we would simplify the aims we have set as part of our sustainability frame to focus on the areas that we believe are most relevant to bp's long-term success. We now have five aims: net zero operations★, net zero sales★, people, biodiversity and water. In some areas we have retired aims we had previously set; however, in many cases work continues in those areas. We provide an update on our actions on those aims, and our wider progress in relation to embedding sustainability, in our latest Sustainability Report **bp.com/sustainability**.

Sustainability aims

Net zero operations	Net zero sales	People	Biodiversity	Water
Our aim is to reach net zero★ by 2050 or sooner for Scope 1 and 2 emissions within bp's operational control[a], including by maintaining 'near-zero' methane intensity★ across our operated producing assets, enabled by supportive government policies.	Our aim is to reduce to net zero the average lifecycle carbon intensity of the energy products★ we sell by 2050 or sooner, enabled by supportive government policies and the decarbonization of energy demand.	Our aim is to support our employees and local communities through the energy transition.	Our aim is to support biodiversity where we operate[b].	Our aim is to reduce our net freshwater use in stressed catchments where we operate.
See **below**	See **page 39**	See **page 60**	See **page 60**	See **page 60**

Reporting on sustainability

In this section, we cover selected sustainability issues along with information in the following areas:

- Performance on our net zero aims, see **page 38**
- Climate-related financial disclosures, see **pages 42-55**
- Our approach – safety, ethics and compliance, our people, 'Who we are' (our beliefs), see **pages 56-60**

Net zero

Our ambition remains to be a net zero company by 2050 or sooner, and to help the world get to net zero.

We have retired some of our previous net zero aims and are focusing our aims on the two areas that we believe are most relevant to our long-term success and to achieving our overall net zero ambition. These are: net zero operations[c] and net zero sales. Both of these aims make explicit what is needed to enable their delivery – and the delivery of the associated interim targets and aims. Our future business and investment decisions, intended to facilitate delivery of our strategy and investor proposition, will also affect the outcomes for these aims.

We believe our net zero ambition and aims, taken together, are consistent with the goals of the Paris Agreement.

By setting a path that enables us to make a positive contribution, working to build out and participate in many of the new energy value chains the world will need, our ambition and aims support the world's progress towards the Paris Agreement.

We provide updates on some retired net zero aims as follows: net zero production★ **page 39**, investment in transition **page 39**, advocacy **page 39**, incentivizing employees **page 59**, and our participation in trade associations **page 60**.

Net zero operations TCFD

Our aim is to reach net zero by 2050 or sooner for Scope 1 and 2 emissions within bp's operational control.

Our interim target is a 20% reduction in our Scope 1 and 2 operational emissions by the end of 2025 against the 2019 baseline. Our current outlook for the end of 2030 is a reduction of around 45% against the baseline.

Informed by this outlook, and the assumptions underpinning it, which may change over time, we have adjusted our previous 50% reduction aim for the end of 2030 to a range of 45-50%, against the 2019 baseline of 54.5MtCO_2e. Our methane intensity target remains 0.20% by the end of 2025.

Scope 1 and 2 emissions

Our combined Scope 1 and 2 emissions were 33.6MtCO_2e – a decrease of 38% from our 2019 baseline. The total decrease includes 18MtCO_2e attributable to divestments and 5.4MtCO_2e in emissions reductions activity.

In 2024 our Scope 1 (direct) emissions were 32.8MtCO_2e – an overall increase from 31.1MtCO_2e in 2023. Of these Scope 1 emissions, 31.4MtCO_2e were from carbon dioxide and 1.5MtCO_2e from methane[d]. The increase was due to project ramp-ups, operational growth in our low carbon businesses and some temporary operational changes such as turnaround activity and operational issues.

a On a CO_2e basis.
b At our new in-scope bp-operated projects and major operating sites.
c This aim is a combination of bp's previous net zero aims ('aim 1' and 'aim 4').
d Due to rounding some totals may not equal the sum of their component parts. This does not affect the underlying values.

These were partially offset by the delivery of emissions reduction projects.

In 2024 our Scope 2[a] (indirect) emissions, decreased by 0.2MtCO_2e, to 0.8MtCO_2e, compared with 2023. The continued use of lower carbon power agreements and a project at our Gelsenkirchen refinery to replace imported steam from a coal-fired power plant with steam produced in our own gas-fired boilers contributed to this decrease.

We report our Scope 1 and 2 emissions on an operational control and equity share basis in the *bp ESG Datasheet 2024*.

bp.com/ESGdata

Methane

In 2024, we started reporting on the basis of our new methane measurement approach across our major operated upstream oil and gas assets. Using this approach, our methane intensity was 0.07% in 2024 (2023 0.05%[b]). Methane emissions from our upstream★ operations used to calculate this methane intensity were 46kt in 2024 (31kt in 2023[b]).

The higher emissions and intensity in 2024 are primarily from flaring due to operational issues in our Tangguh operations and increases as a result of a temporary operating mode, which were quantified as a result of improvements in our measurement methodology. Our real-time methane emissions data, together with our increased technical understanding of methane in flares allowed us to identify this abnormal situation in Tangguh, but, generally, analysis of our 2024 measured data shows that overall methane emissions from upstream operational flaring were lower than previously reported using conventional methodologies (including those mandated by some countries). Marketed gas volumes increased by 8.5% to 3,614bcf in 2024.

We continue to work to reduce operational methane emissions. We remain on track to reach zero routine flaring by 2030 in line with our aim under the World Bank's Zero Routine Flaring Initiative.

Net zero sales TCFD

Our aim is to reduce to net zero the average lifecycle carbon intensity of the energy products★ we sell by 2050 or sooner. We are targeting a reduction in intensity of 5% by the end of 2025. Informed by our strategy reset, and a range of assumptions, we are aiming for an 8-10% reduction by the end of 2030 compared to the 2019 baseline. This is an adjustment to our previous aim of 15-20% against the 2019 baseline.

Average carbon intensity of sold energy products (gCO$_2$e/MJ)[c,d]

	2024	2023	2022	2021	2020	2019
Average carbon intensity of sold energy products	**79**	80	81	81	81	84
Oil/refined products	**91**	91	92	92	93	95
Gas/NGLs	**67**	67	67	67	67	68
Bioproducts[e]	**41**	44	43	44	44	47
Power/heat[f]	**50**	56	29	27	33	28

We have updated our net zero sales methodology to follow a net volume accounting approach, guided by Ipieca's sectoral guidance (2016) for Scope 3 reporting. The approach focuses on identifying the point, for bp, where the largest amount of sold energy products is transferred within a given commodity's value chain[g]. We believe this will better reflect and track our strategic progress over time, see bp.com/basisofreporting.

In 2024 the average carbon intensity of our sold energy products★ was 79gCO_2e/MJ[h]. This represents a 6% reduction from our 2019 baseline, driven by improvements in the well to tank (WTT) emissions of sold products and changes in the sold product mix, which have included strategic investment activities such as the addition of a signification retail power volume as a result of the EDF Energy Services acquisition in 2022 in the US.

Net zero production and transition investment

We have retired our aim related to the estimated Scope 3 (category 11) emissions from the carbon in our upstream oil and gas production★. The estimated Scope 3 emissions from the carbon in our upstream oil and gas production were 322MtCO_2 in 2024 – an 11% reduction relative to our 2019 baseline and a slight increase from 315MtCO_2 in 2023. This increase was mainly associated with an increase in underlying production due to the ramp-up of major projects★ and higher asset performance.

We have retired our aim for more investment into the transition. In 2024 transition growth investment★[i] was $3.7 billion, compared with $0.6 billion in 2019 and $3.8 billion in 2023. It represents around 23% of total capital expenditure★ in both 2023 and 2024, compared with around 3% in 2019.

Our disciplined approach to capital investment means that individual investments will be made

when we consider there to be a clear and compelling business case, in line with our balanced set of investment criteria, see **page 20**.

We will continue to provide guidance on a periodic basis about production volumes and our capital frame. As announced in February 2025, we now expect to invest between $1.5-2.0 billion per year through 2027[j] in what we now refer to as our transition businesses★ TCFD.

Khazzan gas field, Oman

Advocacy related to net zero

While we have retired our previous advocacy aim, our work in 2024 focused on several themes in support of our net zero ambition, including carbon pricing, and policy frameworks that support growth in low carbon hydrogen, carbon capture and storage (CCS), renewables, decarbonizing transport (including EV charging) and bioenergy.

We publish examples of our activity online at bp.com/advocacyactivities.

Key

TCFD	TCFD Recommendations and Recommended Disclosures

a Scope 2 emissions on a market basis.
b In 2024 reported absolute methane emissions from upstream major oil and gas processing sites are based on our new measurement approach. Prior to 2024 these emissions were calculated using a different methodology and therefore the methane intensity reported in those years and calculated using that data does not directly correlate to progress towards delivering the 2025 target. Prior year data is provided for information purposes, and we do not seek to directly compare prior years.
c Previously reported figures for the period 2019-2023 have been restated to update the 2019 baseline and the years 2020-2023 in line with the updated methodology for the net zero sales metric. For more detail on how this metric is calculated see the *Basis of Reporting*: bp.com/basisofreporting.
d The aggregate lifecycle emissions and energy values used in the calculation of the average lifecycle carbon intensity of sold energy products★ are provided in the *bp ESG Datasheet 2024*.
e Includes biofuels and biogas.
f Covers all power, including renewable and non-renewable.
g Commodity groups in 2024 are Oil/Refined Products, Gas/NGLs, Biofuels, Biogas, Power/Heat.
h On the updated methodology basis.
i In February 2025 bp announced that we have retired the concept of transition growth★ engines going forward.
j Excludes deferred consideration for 2024 acquisition of bp bioenergy in 2025.

Net zero aims 2024 performance

Aims	Measure/coverage	2024 performance	2025 targets	2030 aims	Aims for 2050 or sooner
Net zero operations★	Scope 1 and 2★	38%[a]	20%[a]	45-50%[a]	Net zero★
Net zero production★	Scope 3★	11%[a]	–		
Net zero sales★	Average lifecycle carbon intensity[b]	6%[cd]	5%[d]	8-10%[d]	Net zero★
Reducing methane	Methane intensity★	0.07%[e]	0.20%	Now embedded into net zero operations	
More $ into transition	Transition growth investment★	$3.7bn	–		

a Reduction in absolute emissions against 2019 baseline.
b Average lifecycle carbon intensity of our sold energy products★.
c Previously reported figures for the period 2019-2023 have been restated to update the 2019 baseline and the years 2020-2023 in line with the updated methodology for the Net zero sales metric. For more detail on how this metric is calculated see the *Basis of Reporting*: bp.com/basisofreporting.
d Reduction in the average lifecycle carbon intensity of sold energy products against the 2019 baseline. The percentage change is calculated from the source data instead of the rounded carbon intensity number.
e In 2024 reported absolute methane emissions from upstream major oil and gas processing sites are based on our new measurement approach. Prior to 2024 these emissions were calculated using a different methodology and therefore the methane intensity reported in those years and calculated using that data does not directly correlate to progress towards delivering the 2025 target. Prior year data is provided for information purposes, and we do not seek to directly compare prior years.

Streamlined energy and carbon reporting (SECR) information

Further information on our greenhouse gas (GHG) emissions, energy consumption and energy efficiency is set out here and on the following page. It includes disclosures in respect of the SECR requirements. Further breakdown of our GHG and energy data is available in the *bp ESG Datasheet 2024* at bp.com/ESG.

Operational control[ab]	Unit	2024	2023	2022
Scope 1 (direct) emissions	$MtCO_2e$	**32.8**	31.1	30.4
UK and offshore	$MtCO_2e$	**1.0**	1.0	1.0
Global (excluding UK and offshore)	$MtCO_2e$	**31.8**	30.1	29.4
Scope 2 (indirect) emissions – location-based	$MtCO_2e$	**2.4**	2.0	2.1
UK and offshore	$MtCO_2e$	**0.02**	0.02	0.02
Global (excluding UK and offshore)[c]	$MtCO_2e$	**2.4**	1.9	2.0
Scope 2 (indirect) emissions – market-based	$MtCO_2e$	**0.8**	1.0	1.4
UK and offshore[de]	$MtCO_2e$	**0.02**	0.0	0.0
Global (excluding UK and offshore)[f]	$MtCO_2e$	**0.8**	1.0	1.4
Energy consumption[gb]	GWh	**129,872**	124,770	121,697
UK and offshore	GWh	**4,526**	4,688	4,376
Global (excluding UK and offshore)	GWh	**125,347**	120,082	117,321
Ratio of Scope 1 (direct) and Scope 2 (indirect) emissions to gross production[h]	$teCO_2e/te$	**0.16**	0.16	0.15
UK and offshore	$teCO_2e/te$	**0.13**	0.13	0.12
Global (excluding UK and offshore)	$teCO_2e/te$	**0.16**	0.16	0.15

a Operational control data comprises 100% of emissions from activities operated by bp, going beyond the Ipieca guidelines by including emissions from certain other activities such as contracted drilling activities. Read more at bp.com/basisofreporting.
b Due to rounding, some totals may not agree exactly to the sum of their component parts.
c 2022 restated due to IEA emission factor library update.
d 2023 reflects REGOs that had not been retired at the time of publication but are expected to be retired subject to business decisions at the end of the compliance period 31 July 2024.
e 2024 reflects REGOs that had not been retired at the time of publication but are expected to be retired subject to business decisions at the end of the compliance period 31 July 2025.
f 2022 restated due to consistency of rounding.
g Energy content of flared or vented gas is excluded from energy consumption reported as although it reflects loss of energy resources, it does not reflect energy use required for production or manufacturing of products.
h Gross production comprises upstream production, refining throughput and petrochemicals produced.

Streamlined energy and carbon reporting (SECR) information

Energy efficiency measures

Operational efficiency

We take a portfolio view of our project improvement activities at individual sites. This allows us to prioritize the most effective projects, supporting energy efficiency, reduced carbon emissions, and lower costs.

During 2024 we completed energy efficiency reviews in three production regions: Azerbaijan, Georgia and Türkiye, Trinidad and Tobago, and the Gulf of America, US. We started an energy efficiency programme in our refining business, and two refineries, Whiting, US and Rotterdam, Netherlands, have completed it. We expect to complete reviews for the remaining production regions and refineries in 2025. Identified opportunities will be advanced through our existing business processes and plans that support our net zero ambition.

In 2024, a total of 27 new emission reduction projects contributed to reductions of 0.42MtCO_2e. This is in addition to the 172 emissions reduction projects and the associated reduction of 0.9MtCO_2e in 2023. These projects are tracked based on GHG reductions and include energy efficiency improvements.

Emission reduction projects implemented by our businesses in 2024, included low carbon energy consumption projects, which delivered 102ktCO_2e in emissions savings. These reductions were primarily delivered in bpx energy, US and included electrification projects and installation of solar pumps.

Emission savings of ~262ktCO_2e were achieved through energy efficiency improvements in production processes and flaring process optimization projects during 2024. These included:

- Our Gelsenkirchen refinery replaced imported steam from a coal-fired power plant with steam produced in our own gas-fired boilers, reducing emissions by 19ktCO_2e.
- bpx energy's central distribution projects, Karnes and Bingo, enabled decommissioning of legacy natural gas-driven equipment, resulting in reduced flare volumes and the switch from natural gas to instrument air in pneumatic devices.
- Restoration of cooling water infrastructure at Cherry Point to reliably meet refinery needs and improve the efficiency of compressor operations.

Other types of reduction projects delivered a total reduction of 56ktCO_2e, including the hydrocracker improvement project at Cherry Point, US, which saved 26ktCO_2e of emissions.

As part of managing energy efficiency, we take a portfolio-wide approach to assessing and prioritizing spinning reserve reduction opportunities. Spinning reserve involves running additional power generation machines to provide an excess of energy supply. This can help to protect production from plant vulnerabilities, including power generation reliability. Reducing spinning reserve can increase exposure to power fluctuations for production. We take a risk-based approach when considering reducing the number of running machines. This allows bp to realize emissions and maintenance cost reductions from fewer running machines, while managing the associated production risk.

bp is involved in several external groups working on energy efficiency, including the Oil & Gas Climate Initiative (OGCI), the International Association of Oil & Gas Producers (IOGP) and Energy Star. We continue to run an annual training course for new chemical engineers, which includes energy efficiency upskilling, and we offer GHG emissions and energy efficiency training for more experienced engineers and practitioners.

Reporting methodology

Our approach to reporting GHG emissions broadly follows the Ipieca, API, IOGP Petroleum Industry Guidelines and the GHG Protocol for Reporting GHG Emissions. We calculate GHG emissions based on fuel consumption and fuel properties for major sources, such as flares.

We report CO_2 and methane. We do not include nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride as they are not material to our operations.

Energy consumption is monitored and reported centrally from all operated sites by fuel type. This includes all energy, both imported and self-produced, used to run our operations and aligned with our GHG reporting boundary, but excludes energy content of flared or vented gas. Although flaring and venting reflects loss of energy resources, it does not reflect energy use required for production or manufacturing of products.

Ratio of Scope 1 and Scope 2 emissions to gross production

bp reports a ratio of Scope 1 and Scope 2 emissions to gross production, see the SECR table on **page 40**. This covers all our Scope 1 and Scope 2 emissions on an operational control boundary basis and uses gross operated sales from our operated oil and gas facilities, refinery throughput and petrochemicals produced. The denominator uses output from production businesses, refineries and petrochemical facilities, which account for 96% of total operated emissions. The intensity ratio has remained the same as 2023.

The ratio provided in the SECR table uses production and throughput from our operated upstream, refining and chemicals businesses as a measure of output which can be consistently reported against. We report data on a consolidated basis in the Annual Report and Form 20-F and this differs to the production and throughput used for the ratio in the SECR table, which aligns with the operational control boundary basis.

Climate-related financial disclosures[a]

We support the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD), established by the Financial Stability Board to improve the reporting of climate-related risks and opportunities.

We want to continue to work constructively with the IFRS Foundation's International Sustainability Standards Board (ISSB) and others as they develop good practices and standards for transparent climate-related reporting.

In 2024 we continued to engage with the World Business Council for Sustainable Development (WBCSD) in relation to its ongoing 'Climate Scenario Analysis Reference Approach for Companies in the Energy System'. Read about how we have used the WBCSD Scenario Catalogue[b] to inform our own scenario analysis on **page 53**.

TCFD statement

We report in line with the FCA Listing Rule UKLR 6.6.6R(8), which requires us to report on a 'comply or explain' basis against the TCFD Recommendations and Recommended Disclosures in respect of the financial year ended 31 December 2024[c].

We consider our climate-related financial disclosures to be consistent with all of the TCFD Recommendations and Recommended Disclosures and that they are therefore compliant with UKLR 6.6.6R(8). We have set out our disclosures against each TCFD Recommended Disclosure and in doing so have covered both the Recommended Disclosure and the related Recommendation[d]. We have made disclosures that take into consideration references made to the materiality of information in the Recommendations related to Strategy and Metrics and Targets. In determining materiality for these purposes, we considered whether particular information may have the potential to influence the economic decisions of our shareholders. We have also, where appropriate, considered the TCFD guidance and other supporting materials referred to in the UK Listing Rules[e]. In the Strategy (b) section on **page 47**, we describe elements of our plans for the transition to a lower carbon economy as we execute our strategy.

As explained on **page 10**, we consider our strategy to be consistent with the goals of the Paris Agreement.

The strategy has been developed taking into consideration, among other things, the *bp Energy Outlook 2024* scenarios (described on **page 7**), which take account of climate commitments and pledges made by countries in which we operate alongside a range of other factors.

In preparing our disclosures we have made several judgements, and while we are satisfied that they are consistent with the TCFD Recommendations, Recommended Disclosures and reporting requirements under the UK CFD Regulations, we will continue to monitor guidance as it evolves and consider opportunities to enhance our disclosures.

Governance

TCFD Recommendation:

Disclose the organization's governance around climate-related issues and opportunities.

Recommended Disclosure:

a. Describe the board's oversight of climate-related risks and opportunities.

b. Describe management's role in assessing and managing climate-related risks and opportunities.

The board's role

One of the core roles of the board is to promote the success of the company for the benefit of its shareholders as a whole while having regard to various factors, including the interests of our other stakeholders and the impact of our operations on the environment and the communities where we operate.

In performing this role, the board sets and monitors bp's strategy. It is responsible for monitoring bp's management and operations and obtaining assurance about the delivery of its strategy.

Any changes to the company's purpose, strategy and values (which we call 'Who we are') are reserved for the board for approval in accordance with the board-approved corporate governance framework.

The board's responsibilities extend to oversight of bp's internal control and risk management framework, including climate-related risks and opportunities, as set out in the terms of reference of the board, available online at **bp.com/governance**.

The board considers that our strategy allows bp to be flexible to adapt to the evolution of the external environment, including market changes, to remain consistent with the Paris goals, see **page 21**.

The board and its committees have oversight of climate-related issues[f], which include climate-related risks and opportunities. Related board and committee activities are set out within the board activities section and committee reports respectively, which can be found on the pages detailed in the table on **page 43**.

Climate-related risks and opportunities were discussed at each board meeting covering strategy in 2024, and the committees considered climate-related issues where appropriate to do so in fulfilling their responsibilities. Oral reports from each of the committee chairs are given at board meetings to keep the board apprised of the relevant matters discussed including, where applicable, climate-related risks and opportunities.

Our company secretary's office manages the process by which board and committee agendas are set and works closely with teams in bp to develop materials that assist the board to discharge its responsibilities, including in respect of climate-related issues.

The board also reviewed documents containing climate-related disclosures – including these TCFD disclosures.

a This section provides disclosures pursuant to the FCA Listing Rule UKLR 6.6.6R(8) and in line with the Companies (Strategic Report) (Climate-related Financial Disclosure) Regulations 2022 (The UK CFD Regulations). In the main, we consider our TCFD disclosures achieve UK CFD compliance. Where additional information has been provided beyond our TCFD disclosures to achieve compliance with the CFD Regulations, this has been specifically called out.

b Our 2024 analysis used data from the WBCSD Climate Scenario Catalogue version 3.0, published on 16-05-2024 and downloaded on 13-11-2024.

c In considering the consistency of our disclosures with the TCFD Recommendations and Recommended Disclosures we have had regard to, among other things, the documents referred to in UKLR 6.6.8G and 6.6.9G, as applicable to the financial year 2024.

d In preparing the disclosures we have referred to the TCFD implementation guidance 'Annex: Implementing the Recommendations of the Task Force on Climate-related Financial Disclosures (October 2021)', available from fsb-tcfd.org/publication.

e UKLR 6.6.8G and UKLR 6.6.9G.

f We interpret the term 'climate-related issues' to relate primarily to those climate-related risks and opportunities for bp that are relevant to the delivery of long-term shareholder value in the context of the low carbon transition.

Learning and development

The board continues to develop its knowledge and expertise on climate-related and sustainability matters. For example, in 2024, the board took part in the following:

Renewables and power update	Included recent progress on, and plans for, offshore wind. Update provided to assist the board in remaining abreast of key energy transition risks and opportunities.
Hydrogen and carbon capture and storage transition growth★ engine update	Update provided on bp-led projects including the Northern Endurance Partnership, Net Zero Teesside Power and H2Teesside. Assisted the board in remaining abreast of key energy transition risks and opportunities.
Energy and economic update	The briefing was given by our chief economist on developments shaping the key political and societal trends currently affecting the energy transition, in advance of publication of the *bp Energy Outlook 2024* in July 2024. Briefing assisted the board in remaining abreast of key developments.

The board is due to receive further updates on bp's strategic process and sustainability frame in 2025.

Climate and sustainability expertise

The board believes its members possess the necessary expertise related to climate change and sustainability to support the group's strategy. In particular, six of our non-executive directors have specific climate change and sustainability expertise, as set out below.

This determination is based on an assessment of their background and experience, with a focus on their background in the energy sector, experience in executive roles and depth of experience in sustainability and climate change, including climate-related risks and opportunities.

For more general director skills information, see **page 71.**

- **Dame Amanda Blanc** is the current serving CEO at Aviva plc and has held several executive roles across the industry. She was co-chair of the UK Transition Taskforce and Principals Group Member of Glasgow Financial Alliance for Net Zero (GFANZ).
- **Helge Lund** has extensive experience in the energy sector and deep knowledge and global experience including stakeholder considerations regarding climate change risk and opportunities. He has chaired the board through the development of bp's strategy and net zero ambition and continues to have oversight of the delivery of that strategy. He served as a member of the UN Secretary-General's Advisory Group on Sustainable Energy from 2011 to 2014.
- **Melody Meyer** has deep-rooted operational experience in the energy sector which equips her to advise on climate-related risks and opportunities. She has chaired bp's safety and sustainability committee since November 2019, which oversees the implementation of bp's sustainability frame and net zero ambition.
- **Hina Nagarajan** has over 30 years' experience in senior roles within the customer-focused FMCG sector. As CEO of United Spirits Limited (Diageo plc's listed Indian subsidiary), she has overseen the implementation of Diageo India's 10-year ESG action plan, and its Society 2030 mission, in addition to a number of other sustainability initiatives.
- **Satish Pai** has extensive experience in the resource and energies industries. He is managing director of metals company, Hindalco Industries Limited, and leads the company's Sustainability Board in overseeing sustainability initiatives – such as sustainable mining practices, energy conservation and recycling. He has served on the bp safety and sustainability committee since March 2023.
- **Johannes Teyssen** brings CEO experience from his time at EoN, where under his leadership, it split its hydrocarbons and non-hydrocarbons businesses – giving him significant experience of considering climate-related risks and opportunities. He has sat on bp's safety and sustainability committee since 2021. He is a director of Alpiq Holding AG, a Swiss energy services provider and electricity producer in Europe.

Board and committees' consideration of climate-related issues

For examples from the year ended 31 December 2024, see the text indicated with **TCFD** on the pages set out below.

The board

pages 76-77

Safety and sustainability committee

pages 80-81

Audit committee

pages 82-85

Remuneration committee

pages 88-110

Climate-related financial disclosures continued

The role of management

The board, subject to certain conditions and limitations, delegates day-to-day management of the business of the company to the CEO. The CEO is responsible for proposing bp's strategy and annual plan to the board for approval and leading the bp leadership team in delivering bp's strategy and annual plan.

Under this delegation, the CEO is responsible for overseeing the implementation of a comprehensive system of internal controls that are designed to, among other things (a) identify and manage risks that are material to bp, (b) protect bp's assets, and (c) monitor the application of bp's resources in a manner that meets external regulatory standards. Risks, for these purposes, include the climate-related risks and opportunities for bp associated with the issue of climate change and the transition to a lower carbon economy. This is set out in the CEO role profile at **bp.com/board**.

The assessment and management of climate-related risks and opportunities are embedded across bp at various levels and delegated authority flows down from the board through the CEO. See **page 61** for more information on risk governance and oversight.

2024 activity

Where considered appropriate, climate-related risks and opportunities were discussed at bp leadership team meetings in 2024 as part of regular business performance updates prepared for these meetings.

The bp leadership team provides oversight of risk, including climate-related risk, through the various committees described on **page 61**. They are informed about and monitor emerging risks over the short, medium and longer-term via emerging risk papers produced by our SVP treasury. Members of the leadership team receive information on the longer-term risks and opportunities associated with the energy transition via updates produced by our chief economist. These papers are shared with the board.

SVP level and beyond

The bp leadership team is supported by bp's senior-level leadership and their respective teams, with dedicated business and functional expertise focused on climate-related risks and opportunities or on matters which may be affected by such risks and opportunities. This includes: health, safety, environment and carbon; risk; and strategy and sustainability (which includes our carbon ambition, policy and economics teams). Alignment between group, business and functional leaders is fostered through other meetings, such as the TCFD working group which leads the preparation of bp's TCFD disclosures.

Management consideration of climate-related risks and opportunities is organized as follows:

Resource commitment meeting	Forum for approval of investments related to existing and new lines of business above $250 million or $25 million for acquisitions, or which exceed the relevant EVP financial authority, and any project considered strategically important such as a new market entry, see **page 21**.
Group sustainability committee	Provides oversight, challenge and support in the implementation of bp's sustainability frame and the management of potentially significant non-operational sustainability (including climate-related) risks and opportunities. It met four times in 2024. During 2024 the committee considered progress embedding sustainability, performance against targets and bp's position on certain strategic sustainability issues that present risks or opportunities to delivery. This committee is chaired by the EVP strategy, sustainability & ventures (SS&V) and comprises members of the bp leadership team. The outputs from the committee are shared with the board and its committees, including the safety and sustainability committee, as appropriate.
Group operational risk committee	Provides oversight of safety and operational risk management performance for the group, where appropriate. Climate-related factors may affect certain sources of safety and operational risk, such as severe weather events.
Group financial risk committee	Monitors the effectiveness of bp's financial reporting, systems of internal control and financial risk management, namely material group financial risks. Where appropriate, it considers the planned approach to assurance and verification of non-financial reporting ahead of updating the audit committee.

Acquired businesses

Integration plans are developed to transition acquired businesses into bp's system of internal control, over an appropriate timeframe.

Climate governance: management of climate-related matters

As at 1 January 2025

bp board level				
Board	Safety and sustainability committee	Audit committee	People, culture and governance committee	Remuneration committee

EVP level				
CEO **bp leadership team**	**Group sustainability committee** Chair: EVP SS&V	**Resource commitment meeting** Chair: CEO	**Group operational risk committee** Chair: CEO	**Group financial risk committee** Chair: CFO

SVP level		
Sustainability forum Chair: SVP sustainability Focuses on sustainability plans and progress.	**Production & operations carbon table** Chair: SVP HSE & carbon, P&O Focuses on the delivery of lower carbon plans in P&O – particularly in relation to net zero aims.	**Issues and advocacy meeting** Chair: SVP external affairs, C&EA Focuses on policy and advocacy issues, including those related to climate matters.

Cross bp forums and meetings
Meetings and forums to allow cross-group discussions, integration and implementation.

Risk Management

TCFD Recommendation:
Disclose how the organization identifies, assesses and manages climate-related risks.

Recommended Disclosure:
a. Describe the organization's processes for identifying and assessing climate-related risks.

bp's risk management system and policy, described on **page 61**, are designed to address all types of risks including our principal risks and uncertainties, described on **page 62**.

As part of this system, our businesses and functions are responsible for identifying, assessing, managing and monitoring risks associated with their business or functional area.

The process for identifying risks is outlined on **page 62** and guidance to support consistency has been made available to our businesses to provide them with a climate-related framework and taxonomy, which they are able to use as they see fit in their identification and assessment of risk.

Where risks – including climate-related risks – are identified, businesses and functions are required to assess them, in line with our risk management policy. This includes an impact and likelihood assessment which supports the consideration of relative significance and prioritization of risk management activities.

The impact criteria outlined on **page 62** include health and safety, environmental, financial and non-financial (such as regulatory impact) criteria and are used for assessing risks, including climate-related risks. This provides a consistent basis for assessment across bp.

For the purposes of our TCFD disclosures, we use the TCFD's distinction between 'physical' and 'transition' climate-related risks.

Identification, assessment and management of climate-related opportunities[a]

As set out in our TCFD Strategy A and B disclosures on **page 47**, we have identified potentially material climate-related opportunities and our strategy has been informed by these. We identify climate-related opportunities by considering a range of information sources, including the *bp Energy Outlook 2024* (see **page 7**), which helps inform our core beliefs about the energy transition. Business opportunities continue to be originated across bp, and taken forward through bp's investment governance framework, see **page 21**.

Our gas & low carbon energy business is accountable for the delivery of many of our low carbon opportunities through both organic and inorganic growth (see **page 62**). Our investment governance framework (see **page 21**) provides the mechanism by which alignment of these opportunities with our strategy is assessed and decisions on which to progress are made.

a Information added to satisfy the UK CFD Regulations.

Recommended Disclosure:

b. Describe the organization's processes for managing climate-related risks.

c. Describe how processes for identifying, assessing and managing climate-related risks are integrated into the organization's overall Risk Management.

Risk Management process

Risks which may be identified include potential effects on operations at asset level, performance at business level and developments at regional level from extreme weather or the transition to a lower carbon economy.

As part of our annual process the bp leadership team and board review the group's principal risks and uncertainties. Climate change and the transition to a lower carbon economy continues to be identified as a principal risk, see **page 63**. It covers various aspects of how risks associated with the energy transition could manifest. Physical risks such as extreme weather, which may be affected or intensified by climate change, are covered in our principal risks related to safety and operations.

Physical risk

Physical risks are typically identified at the asset or project level and managed depending on the level of risk assessed.

In the North Sea and Gulf of America, regions more prone to severe weather conditions, our offshore facilities monitor meteorological and oceanographic conditions through the collection of measurements. This data is collated and periodically compared against the 'Basis of Design' for the facility. If significant differences are observed, then this may trigger an update to the 'Basis of Design', prompting action to reassess risks such as structural integrity and station-keeping and if necessary, implement additional risk mitigations, for example updating procedures for shutting down and removing personnel from facilities ahead of severe weather events. Updates may also be made as a result of other new knowledge, analysis methods and data, including climate projections where appropriate.

Our major projects★ are required to assess the potential impact of severe weather and projected climate-related physical impacts. Where relevant, potential changes in environmental conditions, such as sea level rise and ambient temperatures, over the expected lifetime of a project are to be considered as part of the design process.

Building on a modelling exercise conducted in 2022, in 2024 we implemented a screening approach to support identification of potential severe weather and physical climate-related hazards at operational sites. Screening was conducted for a number of onshore sites and, where potential hazards have been identified, and as appropriate, this enables further work to be carried out to assess potential risks and implement appropriate management measures.

For other assets, such as our retail sites★, that are typically not exposed to a comparable level of severe weather risk, climate-related risks such as flooding or wind damage may be managed where appropriate through the emergency response plans and business continuity plans which are mandated through bp-wide policies.

Additionally, at a group level we recognize risk associated with the potential for increased water scarcity due to climate change and other factors and the impact this could have on our operations and in the catchments where we operate. In order to understand the water-related challenges that we face, we review our water impacts, risks and opportunities at our major operating sites. These reviews consider the quantity and quality of water used as well as any regulatory requirements. We anticipate adopting site-level activities as part of our aim to reduce our net freshwater use in stressed catchments where we operate. We anticipate adopting a focused freshwater management approach, addressing water-related business risk where it is greatest, and we anticipate that our freshwater withdrawal in stressed catchments will be covered by freshwater management plans by 2028. For more about water, see **page 60**.

Transition risk

The board appraises bp's strategy and monitors bp's management and operations to obtain assurance over the delivery of its strategy. This approach enables the effective management of climate-related transition risks and opportunities facing bp associated with the energy transition. For the purposes of our TCFD disclosures, we group transition risks identified by our businesses and functions into the three broad material climate-related transition risks to bp, see **page 48**. However, we continue to assess and manage the component parts of those broad transition risks, including:

Policy and legal risks

Our policy team monitors policy trends and leads the definition of policy positions in line with bp's strategy and sustainability aims. They work with our regional organization as well as corporate entities to discuss regional and global policy trends and support external positioning and interactions relating to policy and advocacy topics.

Our group sustainability committee provides oversight of sustainability matters and our issues and advocacy meeting covers emerging advocacy issues.

Our legal team manages bp's litigation, including climate-related litigation and advises on the management of associated risks. This includes the use of internal lawyers and, where appropriate, external counsel.

Market risks

In developing our business strategies, we consider market risks, controls and mitigations, including future demand in the different geographies in which we might operate, the competitive landscape and the potential value proposition. We manage these risks through our investment decisions, our hedging and optimization activity, and through key business processes, including the group investment assurance and approval process.

Reputational risks

Our investor relations, communications and external affairs teams work to mitigate reputation-related risks, which include the risk of shareholder action. Our investor relations team co-ordinates engagement with key investors on both a bilateral basis and through investor initiatives to support understanding of bp's strategy and gain insights to inform feedback they provide to the group.

Our communications and external affairs teams manage corporate reputation through identification and monitoring of key issues and both proactive and reactive engagement with relevant stakeholder groups to communicate bp's positions. The team also leads advocacy campaigns for policies that support net zero, see **page 39**.

Technology risks

Our technology team works to both mitigate risks and identify opportunities associated with evolving and emerging technologies that play a role in the changing global energy system. The team generates technology assessments and disruptive technology reports for review by bp senior executives and the recommendations are overseen by the bp leadership team, through the Innovation Advisory Council. In appropriate cases this helps to underpin and appraise the business case for new investments, new partnerships, new customer offers or new business models where these are being driven by technology innovation.

Strategy

TCFD Recommendation:
Disclose the actual and potential impacts of climate-related risks and opportunities on the organization's business, strategy and financial planning where such information is material.

Recommended Disclosure:
a. Describe the climate-related risk and opportunities that the organization has identified over the short, medium, and long term.

In setting and monitoring delivery of bp's strategy, the board and leadership team consider climate-related risks and opportunities across the:

- **Short term** (to 2025): aligning with our near-term business and financial planning timeframe.
- **Medium term** (to 2030): aligning with our group business outlook timeframe, and enabling us to think beyond our short-term targets and adjust course if appropriate.
- **Long term** (to 2050): using scenarios to help explore the wide range of uncertainties surrounding the energy transition over the next 25 years. For more detail on our approach, see **page 7**.

TCFD categorizes climate-related transition risk and opportunity as follows: policy and legal, market, reputation and technology. It also refers to climate-related acute and chronic physical risks and opportunities. Risks in each of these categories have been identified using a risk management process that our businesses and functions are required to follow. For more about how the relative significance of identified risks is evaluated, see Risk Management on **page 45**.

Climate-related transition risks and opportunities

At a group level, we have identified three broad, material climate-related transition risks, outlined on **page 48**, underpinned by underlying risks that are assessed and managed through the risk process outlined. These transition risks may cut across our short-, medium- and long-term time horizons; however, we indicate below wherever there is a particular time horizon in which the risk has been considered. The transition risks are also global in nature, so we do not discuss specific geographies here, but the underlying risks refer to specific geographies where appropriate[a]. We also see significant potential for upside – or opportunity – associated with some of these risks. These are discussed under each risk on **page 48** and in relation to Recommended Disclosure (b) we also describe the potential impacts of both the risks and opportunities to bp.

Climate-related physical risks

The physical risks identified primarily relate to severe weather and often represent potential for increased drivers for safety and operational risks to our operations, particularly process safety, personal safety, and environmental risks, see Risk factors **page 65**. In addition, we have identified the potential for changes in the availability of freshwater, including as a result of climate change, as a risk to some of our operations. Higher instances of extreme weather also have the potential to impact supply chains and critical infrastructure, such as air and sea ports, as well as our customers.

We recognize that we could also face other forms of physical climate-related risk over the longer term, for example associated with changes in sea level rise, extreme temperatures and flooding, which could impact our operations. As these risks are primarily operational, and location-specific, they are not grouped in the same way as transition risks.

Like other businesses around the world, in the longer term we could face adverse market or value chain conditions associated with large-scale cumulative impacts of physical climate change if global mitigation and adaptation efforts are insufficient or unsuccessful.

Offshore facilities

In the case of our offshore facilities, climate change could create greater uncertainty around frequency and/or intensity of severe weather events, such as extreme waves, loop currents, and storms, particularly in the medium to long term. These factors could affect the future risk profile of an asset over its lifetime, and could also impact production or costs.

Water resources

Water resources are increasingly under pressure from various factors, including climate change, and this poses a potential risk to some of our operations that depend on the availability of freshwater. Based on analysis using the World Resources Institute (WRI) Aqueduct Global Water Risk Atlas, and in certain cases review of site-specific local data sources, six of our 16 major operating sites in 2024 were located in regions with high to extremely high water stress. Using WRI data, we have identified the potential for this risk to increase in the medium term. For more on water consumption, see **page 60**.

We support the goals of the Paris Agreement and believe that the best mitigation against these types of physical risk is to seek to contribute along with others to the success of global climate mitigation efforts. Our strategy seeks to position us to make such a positive contribution.

We do not currently foresee any material opportunities arising from changes in the physical environment as a result of climate change. However, the actions we are taking to make our operations more resilient, for example through improving efficiency of our freshwater use, may also bring about benefits such as reduced costs.

Recommended Disclosure:
b. Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy, and financial planning.

bp's plans for the energy transition

In this section we talk about some of our plans for the transition across bp's business areas and where we do so we have identified these with **TP**.[b] We describe below how we believe our strategy and net zero ambition are both good for business and support society's drive towards the Paris goals.

Throughout the strategic report we set out bp's strategy and plans for the energy transition. This includes our progress against 2024 performance, see **page 9**.

Our progress against our net zero aims are described on **pages 38-39.**

TP Our strategy, together with our net zero ambition and aims (see **page 40**), has been informed by various inputs, including the climate-related risks and opportunities associated with the energy transition described above; the same is true of our financial and business processes. We describe how we use scenarios to inform our strategy on **page 7**.

a Underlying risks are specific, for example, local or business-specific risks identified by specific bp entities through the risk processes described above under Risk Management.
b This is not intended to be an exhaustive list of our plans for the transition, but rather illustrative of some of the core elements of our plans.

Climate-related transition risks and opportunities

#1 **The value of our hydrocarbon business could be impacted by climate change and the energy transition.**	**Changes in policy, legislation, consumer preferences or markets as a result of growing concerns about climate change and the energy transition could reduce demand for fossil fuels or lower their price relative to our financial planning assumptions, particularly in the medium to long term, negatively impacting returns from or the value of our hydrocarbon businesses. Changes in regulations, including carbon pricing and fossil fuel policies, could also impact compliance and operating costs in our oil and natural gas production and refining businesses.** Alternatively, demand and/or prices for oil and natural gas and refined products during the next decade could be higher than our financial planning assumptions under certain transition pathways, including those aligned with the Paris Agreement. This could strengthen returns from our hydrocarbon businesses (including securing higher proceeds from assets we choose to divest) which may enable us to deliver enhanced shareholder value, further strengthen our balance sheet and grow investment in the transition, in line with our financial frame.
#2 **Our ability to grow or deliver expected returns from our transition businesses★ could be impacted by the energy transition.**	**Several factors could restrict the growth of our transition businesses★ or returns from them. These factors include: lack of, or insufficient development and application of, policies, regulations and frameworks that support low carbon businesses; insufficient consumer demand for our low carbon offering; strong competition in the market; or the insufficiently rapid development of supporting technologies and infrastructure or constraints on supply chains for low carbon energies. This could particularly impact bp in the short to medium term as we seek to grow our low carbon businesses but could also represent a longer-term risk.** Alternatively, demand, policy support or enabling technology and supply chain growth for renewables could support a more rapid portfolio shift with expansion of our low carbon businesses and higher returns from them. Some low carbon businesses, including renewable power, bioenergy and emerging technologies such as hydrogen and carbon capture and storage (CCS), rely on policy support to promote growth. We aim to advocate more actively for policies that support net zero, including carbon pricing (see **page 39**). Changes in customer preferences, pace of technology and infrastructure development and deployment and costs could impact the markets for low carbon products and services. For example, the pace of adoption of electric vehicles (EV) could impact utilization rates, and consequently returns, from our EV charging networks. We recognize that the pace of our transition relative to our core low carbon target sectors and regions is important. If we move more slowly than those markets, we may miss investment opportunities and customers may prefer different suppliers with potential negative consequences to demand for our products and to our reputation. If we move faster than these markets, we risk investing in technologies or low carbon products that are unsuccessful because there is insufficient demand for them. However, our investment may also help to stimulate demand and provide us with a leading position in growth markets.
#3 **Our ability to implement our strategy could be impacted by changing stakeholder attitudes towards the energy sector, climate change and the energy transition.**	**Negative perceptions of the energy sector, or bp, could have a number of consequences, for example: adverse litigation; reputational impacts, including our ability to attract and retain talent; and shareholder action. These consequences could affect us in the short, medium or long term.** Alternatively, increased support from our stakeholders could enable access to additional capital and new investors, strengthening our ability to deliver our strategy and enabling faster growth of our low carbon businesses. The world is in an 'energy addition' phase of the energy transition in which it is consuming increasing amounts of both low carbon energy and fossil fuels. The *bp Energy Outlook 2024* (as described on **page 7**) highlights that, although the structure of energy demand will likely change over the long term, with the importance of fossil fuels declining, replaced by a growing share of low carbon energy, led by wind and solar power, oil and natural gas continue to play a significant role in the global energy system for the next 10-15 years. This requires continuing investment in upstream oil and natural gas. The insights from the *bp Energy Outlook 2024* support our view that investment into oil and gas will be needed for decades to come and also that, while the pace and shape of the transition in the long run is uncertain, we continue to see the energy transition as a significant opportunity to grow value. Perceived inconsistencies between the pace of bp's transition and societal expectations could have reputational and commercial impacts that might impair our ability to deliver our strategy. However, we also see potential to positively differentiate bp, by delivering against our strategy, net zero ambition and sustainability aims.

Oil and gas

As announced in February 2025, we are increasing upstream investment versus our prior guidance. This additional investment allows us to strengthen the portfolio, for example the redevelopment of several giant oilfields in Kirkuk, Iraq, **page 32**, underpinning expected growth in underlying production to 2.3-2.5mmboe/d in 2030, excluding future potential divestments. We recognize that the transition presents uncertainty for our upstream business, including the possibility of lower oil and gas prices, but in recent years we have made strong progress improving operational reliability and commerciality across our portfolio, and we retain optionality to divest some lower margin barrels by 2030. We intend to maintain the disciplined application of our balanced investment criteria, which include the consideration of hurdle rates of 15% from a balanced portfolio across oil and gas. Read more about our investment process on **page 20**.

As an outcome of our strategy and informed by our current outlook, and its underlying assumptions, which may change over time, we are aiming for the Scope 1 and 2 emissions from our operations – the majority of which are associated with the operating assets in our hydrocarbons portfolio (refining and upstream oil and gas combined) – to be 45-50% lower at the end of 2030 than in 2019 and we plan to maintain 'near zero' methane intensity★ across our operated producing assets, see **pages 38-39**.

TP Customers and products

As announced in February 2025, we are focusing the downstream – our customer and products business – reshaping the portfolio to focus on markets and businesses where we have advantaged and integrated positions.

We recognize the risk of a decline in demand for conventional vehicle fuels and products due to the energy transition and are working to increase the efficiency and resilience of our existing fuels and lubricants businesses through operating cost reductions and margin optimization. We are also increasing the resilience of our existing fuels network, high-grading our regional footprint and reallocating capital into our most advantaged positions on major transit routes where we see sustained demand for fuels and EV growth. Since 2020 we have announced our exit from two retail markets, and the sale of another. Our integrated mobility model across fuels (hydrocarbons and biofuels), convenience and EV charging provides resilience to the pace of transition by allowing us to flex our offer to meet customer demand.

We are also leveraging our brand in the fast-growing synthetics segment and building exposure to the growing industrial segment. In Aviation, we will make selected high-return investments to build our footprint; and see strong growth potential in sustainable aviation fuel through the transition.

Our biofuels business is already playing a key role in building resilience to the energy transition – helping to decarbonize the mobility value chain using existing infrastructure. We recently took full ownership of bp bioenergy in Brazil, accessing around 50kb/d of production and see potential for future growth with support from policy and market conditions. Our feedstock positions (such as our strategic collaboration with Corteva aimed at producing and delivering crop-based biofuel feedstocks) also provide additional resilience and opportunity to anticipated supply shortages in the transition, see **page 35**.

At our refineries, the energy transition could impact demand for certain products in the future, potentially leading to lower margins and requiring less efficient refineries to be retired. Consequently, we are continuing to drive greater competitiveness and value from our refineries, aiming for 96% or above Solomon refining availability. We are also repositioning our refining portfolio (see our announced plans to market the Gelsenkirchen complex for example (**page 35**)) and building resilience through value chain integration (US, Spain) and future biofuels.

TP Low carbon energy

Recent volatility and uncertainty has impacted low carbon energy businesses globally, demonstrating the need to be aligned with and flexible to market and policy development. As announced in February 2025, we are changing our model for low carbon – delivering with partners and with external financing that will be capital-light for bp and help improve our equity returns. In renewable power we now have the Lightsource bp platform, and have announced an agreement to form another – JERA Nex bp. Recognizing the exposure to transition volatility seen in recent years, JERA Nex bp plans to focus on highly disciplined, capital efficient growth. We will also maintain access to our equity share of power offtake to support our own growing internal demand. Lightsource bp is now scaled to deliver 3-5GW annually, backed by around 50GW mature pipeline with further potential to scale while remaining capital-light for bp.

In our hydrogen and CCS businesses, we are prioritizing fewer, higher value projects in the near term while building capability and future optionality to scale and grow as the market develops. By focusing on projects in jurisdictions where we have an adequate regulatory framework, access to the value chain including our own or customer demand and leveraging access to advantaged carbon capture and renewable power, we aim, over time, to decarbonize our operations and help our customers decarbonize. We sanctioned four projects, for example, Lingen, Germany in 2024 (see **page 23**) and have a strong pipeline with which to respond to future demand growth.

TP Supply, trading and shipping (ST&S)

Our ST&S business provides risk management, flow and optimization services to our bp equity and assets, with a proven track record of resilience to commodity cycles and the ability to capture upside when market conditions present greater opportunities.

Our diversified oil business helps mitigate the risk of falling demand in the US and Europe by providing access to growing demand centres such as Latin America and Sub-Saharan Africa and in growth markets such as petrochemicals, while our LNG portfolio offers flexibility through our advantaged key global positions.

Together with traditional hydrocarbons, we are positioned to access growth markets, creating diversification and greater resilience across power, biogas, biofuels and adjacent agriculture commodities. Our power trading business allows us to optimize across the value chain from generation across grid markets to customers. This helps position us for further electrification of the energy system as well as further decarbonization of electricity.

Through Archaea, we believe we are uniquely positioned in the US to meet growing demand for biogas as the transition progresses. Our business is integrated across the value chain, enabling us to capture rent as the market evolves. We are building resilience by improving capital efficiency and reducing operating costs and continue to assess and develop new routes to market and customer solutions to create future optionality.

Impact on technology

We are investing in digital and technology solutions that can help to generate value for bp, manage risk and help accelerate the transition through focused scale-up and innovation. This investment includes targeted focus on research and development where bp is and can be differentiated and growing partnerships to increase leverage. We expect our research and development spend to be increasingly focused on technologies with the potential to help identify and access new oil and gas opportunities at lower cost, reduce GHG emissions and enable our low carbon energy businesses. See **page 36** for examples of technology investments in 2024.

We recognize the potential for disruptive technologies to impact our strategy. Alongside our research and development investments, our bp ventures portfolio also includes investments in emerging technologies and business models that may help enable the transition to a low carbon economy, including increasing focus on oil and gas technologies.

★ See glossary on **page 351**

Physical risk

The potential impacts of the types of physical risks we have identified could include reduced production, throughput or sales – for example as a result of damage to facilities or supply chain disruption – or in a most extreme case loss of life or an asset. Due to uncertainties associated with the impact of climate change on severe weather events in the future, it is difficult to quantify the potential impacts associated with any increase in these risks as a result of climate change.

Having considered both geographic factors and the ability of climate models to adequately represent future trends in physical climate parameters, we seek to take the uncertainties concerning climate-related physical risk into account in our approach to design and operating criteria for existing assets and new major projects★. Where appropriate, we have updated our metocean design criteria to include consideration of both forward-looking and historic models, including climate and synthetic models, in an attempt to mitigate both models and extrapolation uncertainty. The particular models chosen will depend in part on geographic location. See Risk Management, **page 45** for how we manage these uncertainties.

As a step in seeking to improve the resilience of our operations to the physical changes that might result from climate change that we have described above, we have undertaken screening of present-day and future potential physical risk exposure for selected key assets and identified those sites with potential for heightened exposure to physical risks in order to prioritize these for further site-based assessment.

Recognizing the potential impact of climate change and other factors on water resources, as part of our water aim (see **page 60**), we are taking steps to be more efficient in operational freshwater use (read more about water use on **page 60**).

Impacts on our financial planning

Capital allocation: We plan to invest sufficient capital to execute our strategy, enabling us to mitigate the risks and capture the opportunities we have identified. As part of our annual planning processes, we assess the distribution of capital across our business areas, including consideration of market evolution. In February 2025 we announced that we expect capital expenditure to be around $15 billion in 2025; and in a range of $13-15 billion through 2026 to 2027. To help maintain resilience to the pace of transition and access opportunities, we will continue to flex capital as policies, technologies and markets evolve.

Access to capital: While there is 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 funding in the short to medium term. We are committed to strengthening our balance sheet, introducing a net debt target of $14-18 billion[a] by the end of 2027 to further improve credit metrics within the 'A' range. In 2022 we reduced our net debt by over $9 billion and by a further $0.5 billion in 2023. In 2024 net debt increased from $20.9 billion to $23.0 billion, reflecting acquired debt from the bp Bunge Bioenergia and Lightsource bp transactions. Since the end of 2019 we have repurchased around $24 billion of short-dated existing bonds and issued over $12 billion of new bonds with a duration of 20 years or longer, doubling the duration of our debt book. Additionally, we have continued to have good access to the commercial paper markets. We provide more detail on financial risk factors, including liquidity risk in Financial statements – **Note 29**.

Investment criteria: Investments are evaluated against a balanced set of investment criteria - for example assessment of economics includes a set of price assumptions that reflect our view of market evolution (for our key investment appraisal price assumptions, see **page 20**). In addition, the investment economics for all investment cases where bp's share of annual greenhouse gas (GHG) emissions from operations are anticipated to exceed specific thresholds include a carbon price for those emissions, that rises from 2025 levels to $135/te$CO_2$e (2023 $ real) in 2030.

When taking investment decisions we continue to consider six balanced investment criteria – including sustainability (see **page 22**).

Impacts on financial performance and position

Assessing the impact of climate change and the energy transition requires the use of a number of judgements and estimates. We have set out the significant accounting policies, judgements and estimates used in assessing the impact of climate change in Financial statements – **Note 1**.

This includes information on pricing, useful economic lives, timing of implementation of policies or decommissioning provisions, and assumptions related to how each might change over time and how such assumptions may impact our currently reported assets and liabilities.

Our price assumptions, including those set out on **page 20**, reflect a range of future possible scenarios and take account of the potential impact of climate-related risks and opportunities as well as current economic and geopolitical factors. Consequently, impairment losses and impairment reversals consider inputs that arise from climate change and the energy transition. It is not possible to quantify separately the impact of these different inputs on our impairments. However, in conducting our impairment sensitivity tests, that in part reflect transition downside risk, we consider reductions in revenue that, if driven by price alone, would be consistent with prices within the range covered by the 1.5°C scenario family within the WBCSD data sets used for TCFD resilience testing below.

Financial statements – **Note 1** provides information on impairment assumptions and sensitivities. **Note 4** provides information on gains and losses on disposal or closure of business and operations, and impairments and impairment reversals, and **Note 8** provides information on impairment losses relating to exploration for and evaluation of oil and natural gas resources. See Financial statements – **Note 1**, **Note 4** and **Note 8** for more information.

Recommended Disclosure:

c. Describe the resilience of the organization's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario.

We believe our strategy positions bp for success and resilience in a Paris-consistent world – a world that is progressing on one of the many global trajectories considered to be Paris-consistent, and ultimately meets the Paris goals, see **pages 10-11**.

As in 2023, to help test our view of this, we have assessed the resilience of our strategy to different climate-related scenarios, including 1.5°C consistent scenarios. We did this in three steps:

1. First, we evaluated all business areas in our portfolio by i) quantitatively assessing their financial significance, in the context of bp's total financial outlook, to understand the potential scale of financial/strategic impact that could be put at risk if exposed to transition uncertainty, including 1.5°C; and ii) considering whether there is a key variable – such as price, margin or demand – which would represent a principal transition driver of such risk.

a Potential proceeds from any transactions related to *Castrol* strategic review and announcement to bring a strategic partner into Lightsource bp will be allocated to reduce net debt.

2. Second, we quantitatively assessed the impact, to each business area, of potential transition exposure scenarios in 2030 – the point in our planning horizon at which there is widest transition uncertainty.
   - For each of those business areas with both sufficient scale and for which a specific transition risk driver was identified – which collectively represent over 80% of our 2030 adjusted EBITDA★ outlook – we performed a scenario analysis focused on that transition risk driver, across a range of transition pathways[a], including 1.5°C, as set out below and in our methodology summary on **page 53**.
   - For each of the remaining business areas we performed a simplified quantitative scenario analysis, by testing the financial impact of a scenario in which each business area's expected 2030 adjusted EBITDA is assumed to be reduced to zero – an outcome at least as detrimental to that business area's adjusted EBITDA as could reasonably be expected to result from business-as-usual (BAU), well-below-2°C and 1.5°C transition pathways.

   In this way, all business areas were quantitatively tested at, or beyond, a range of transition scenarios.
3. Finally, on the basis of the results of steps 1 and 2, we identified those business areas for which the possible consequences of the downside scenario(s) were sufficiently significant to potentially jeopardize group strategic resilience – the only business areas for which this was found to be the case were oil and gas production with respect to their exposure to oil price. For these business areas we assessed the potential implications for bp's strategic resilience (as defined below) over the full period from 2026 to 2030.

To undertake steps 2 and 3, we identified financial criteria which can be modelled as proxies for strategic resilience – choosing to do this through three lenses consistent with our financial frame (as set out on page 18), being our ability to deliver:

i. a stronger balance sheet that improves our credit metrics within the 'A' grade range;
ii. resilient dividend and sharing of excess cash with shareholders through buybacks over time; and
iii. disciplined investment allocations within our capital frame.

This is not intended to represent a 'definition' of resilience beyond the purposes of this exercise, and a core assumption of this analysis is necessarily that, aside from any implications of the scenarios being tested, including potential controllable mitigations such as capital or cost management that we might naturally expect to take in response, bp will deliver the assumed underlying strategic and financial priorities out to 2030.

Our approach, described in more detail on **page 53**, is directly applicable to transition risks #1 and #2 – as well as their associated opportunities – as these lend themselves to a financially quantified scenario-based analysis. The approach does not directly address transition risk #3 – however, we believe that some of the potential drivers for transition risk #3, namely policy and societal trends, may be implicit in these scenarios, and we believe that the successful execution of our strategy will, over time, help to mitigate this risk to bp as well as positioning us to take advantage of the potential associated opportunities. This scenario analysis exercise also does not directly address climate-related physical risk, our strategic resilience to which is further discussed below.

Key insights from our scenario analysis and resilience test

While the results of any such analysis must be treated with caution – each is necessarily dependent on numerous assumptions and methodological choices, and each has its own limitations – overall, this analysis and resilience test reinforced our confidence in the continued resilience of our strategy to a wide range of transition scenarios, including those consistent with limiting temperature rise to 1.5°C, and in particular, as our greatest transition exposure, to oil price scenarios, tested to 2030.

In undertaking this analysis we observed:

- There is considerable uncertainty across, and often within, each WBCSD Scenario Catalogue family in the pace and nature of the transition to 2030 – and therefore considerable range of potential financial impact across some of the variables selected for the analysis, reflecting the complexity and interdependencies of the energy transition (see table on **page 54**). Generally, we observed that the faster the pace of transition, the greater the uncertainty in the exact shape of the resulting energy system in 2030.
- Oil price is likely to remain the main source of climate-related transition uncertainty for our strategy through to 2030, reflecting both the wide range of potential pathways and the contribution to our expected total adjusted EBITDA over this period, that oil-price-linked businesses represent[a]. In the 1.5°C family, the potential downside suggested by the lowest oil prices is around 30% of group adjusted EBITDA in 2030. However, in a number of the scenarios based on the WBCSD Scenario Catalogue ranges, including those consistent with 1.5°C, well-below 2°C and BAU families, oil price could offer a financial upside relative to our reference 2030 group business outlook.
- Even with the most extreme low oil price environment in any of the scenarios, sustained over the period from 2026-30[b] and taking into account our ability to optimize within the frames set out in our strategy (above), and the spend mitigations that we would naturally be expected to see or to make in a lower oil-price world, in our analysis we are able to deliver across the three lenses we use to consider strategic resilience for TCFD purposes, described above.
- The maximum potential scale of downside impact on our 2030 expected group adjusted EBITDA (across the 1.5°C, well-below 2°C and BAU scenarios) from our other natural gas businesses was around 5%, while from each of our conventional refining, fuels and low carbon activities★ was modelled to be <3%.
- Our diversified portfolio helps mitigate the implications for our strategic resilience of the exposure of any one of the individual business areas to the identified risk. It is reasonable to consider each potential outcome in isolation since the outcomes for different business areas vary across scenarios (see table on **page 54**).
- In a BAU scenario, we believe our strategy mitigates the risk of what we and others have referred to as a 'delayed and disorderly' transition, which might follow in the medium to long term. Should the growth of any one of our in-scope transition business★ areas be challenged by the downside range in the relevant variable, our analysis suggests that the impact of this on group adjusted EBITDA in 2030 would not be sufficient to impact the resilience of our strategy, as described above, in that timeframe.

It is important to note that insights from this analysis are necessarily limited by the scenarios, methodologies and business assumptions used. The analysis should not be taken as a prediction of the future.

a Although such scenarios do not and cannot represent all possible futures, we value them as a simplified and schematic way to consider the potential implications of, and uncertainty inherent within, a range of possible energy transition pathways to a future bp portfolio mix.
b Note that for the purposes of our scenario analysis and resilience test, we have assessed the impact of oil price across both our oil production businesses and those natural gas businesses for which commercial outcomes are linked to oil price.
c Our multi-year (2026-30) oil price resilience test considered sustained low oil prices consistent with the most extreme WBCSD Scenario Catalogue 2025 and 2030 scenarios – for 2025 the UN PRI (Inevitable Policy Response Forecast Policy Scenario) at \$54/bbl, and for 2030 the UN PRI (Inevitable Policy Response Required Policy Scenario) at \$34.2/bbl (both 2022 \$ real, and then inflated in line with bp's other planning assumptions, and intervening years interpolated between the two years).

★ See glossary on **page 351**

Maintaining strategic resilience to the transition

Taking into consideration potential constraints associated with factors such as long-term capital investment, contractual commitments and organizational capabilities at any given time, bp's ability to maintain strategic resilience rests, in part, on the governance used to keep the strategy under review in light of new information and changing circumstances.

To enable us to understand and respond to the changing pace of the energy transition, we monitor and assess key indicators and metrics, such as policy development, renewables installed capacity, EV sales and low carbon technology costs. Our strategy and capital allocation, the associated risks, opportunities and (by association) their implications for our resilience are all reviewed by the bp leadership team and the board and updated as they consider appropriate.

Resilience to physical risk

As described on **page 50**, we have identified a number of physical risks which may affect our business and assets, the frequency or severity of which could be affected by climate change. Exposure to physical climate-related risk is highly dependent on geographical location and on factors such as asset design, and we seek to manage these risks accordingly. We consider that our approach to managing these risks, described in Risk Management Recommended Disclosure b) on **page 47**, supports our strategic resilience to them.

For the purposes of this Recommended Disclosure, we have considered the potential for physical risks to bp-operated assets to increase as a result of climate change (namely, increases in the potential frequency or intensity of extreme weather events) to such an extent as to have the potential to impact the resilience of our strategy. We have undertaken analysis of potential changes in certain physical conditions, such as air temperature, precipitation, sea level rise and wave heights, for our onshore and offshore major operating sites, based on Shared Socioeconomic Pathway[a] (SSP) emission scenarios 1-2.6, 2-4.5 and 5-8.5.

Even in the highest emissions pathway (SSP5-8.5) the results of our analysis suggest that, on the basis of the 50th percentile values and compared to the baseline used (1991-2020), changes in the physical parameters considered are generally unlikely to be significant over the medium term.

There is, however, uncertainty across different scenarios and wider variances were observed when looking at the 5th and 95th percentile values. Where the data do suggest greater potential for climate-related changes in physical conditions, we intend to consider whether further work is necessary to understand the potential for those changes to adversely impact our operations. For example, modelled changes in extreme precipitation by 2030 (50th percentile values) are less than 10% across all onshore major operating sites apart from Oman – where we have already undertaken hydrological studies and flood risk assessments that have supported the development of our operations there.

Our transition risk scenario analysis identified impacts on the earnings of our oil-priced businesses as having the most potential to impact the resilience of our strategy in 2030. Therefore, and viewing resilience through the same lenses that we describe above, we have considered the extent to which our oil and gas production business would need to be impacted by evolving physical risk over the same timeframe for the scale of financial impact to be sufficient to jeopardize the resilience of our strategy out to 2030.

We concluded that a significant proportion of our combined oil and gas portfolio would need to be either permanently or temporarily shut in for strategic resilience to be jeopardized in this way.

Historically, severe weather risks to our operated assets have not occurred at a scale which could reduce earnings so significantly as to jeopardize the resilience of our strategy. As reflected in the latest science from the IPCC, it is in the nature of climate-induced severe weather events that their occurrence, intensity and severity are unpredictable and uncertain. Our own analysis on major operating sites, described above, is consistent with this IPCC view.

Despite this uncertainty, we have found no definitive basis in either the IPCC report or the limited number of detailed studies we have undertaken (see **page 50**), to conclude that climate-change-induced increases in the frequency or severity of severe weather events would be likely to result, at any point in time out to 2030, in disruption and shutdowns across our oil and gas portfolio on a scale that would reduce earnings so significantly as to jeopardize the resilience of our strategy.

For the purposes of this Recommended Disclosure, the resilience of our strategy was considered separately for the relevant transition and physical risks; accordingly, we did not seek to take account of any interdependencies or cumulative effects between the two types of climate-related risk, and the associated potential financial impact.

a SSPs have been developed by the climate change research community to describe plausible major global developments that together would lead in the future to different challenges for mitigation and adaptation to climate change. The SSPs are based on five narratives describing alternative socioeconomic developments, including sustainable development, regional rivalry, inequality, fossil-fuelled development and middle-of-the-road development.

Our approach to testing resilience to transition risk

Most of our analysis focused on our medium-term time horizon (2030) – far enough ahead to provide a divergent range of scenarios, while not so far ahead that it is unrealistic to attempt to generate credible financial metrics for bp, or an individual business area within bp. For the variable(s) considered most significant (see below), we also assessed resilience over the period 2026-30.

Our analysis sought to quantify the potential impact of a range of scenarios, including those consistent with 1.5°C, on bp's currently held (at the time the analysis was completed) internal reference group business outlook to 2030. This outlook is used for internal corporate planning and holds a current deterministic view of our portfolio, activity set, cost and capital frame. The outlook used in our analysis aligned to the strategic direction shared at the 26 February 2025 Capital Markets Update, and the financials are assessed against the financial priorities set out in that announcement.

The steps we took as part of our scenario analysis approach are outlined here at a high level.

1. **Whole company assessment:** We defined, through quantitative analysis, which business areas could have both the financial scale and clear transition exposures to potentially impact bp's strategic resilience.
   a. We assessed the business areas in our portfolio by i) quantitatively evaluating each business area's 'potential significance' by its expected contribution to bp group adjusted EBITDA★ in 2030 and therefore the quantum of financial impact that might be put at risk by transition uncertainty (including pathways consistent with 1.5°C); and ii) by identifying, for each, whether there were primary potential value driver(s) that different transition pathways might impact ('transition risk driver(s)'). This was performed to allocate the most appropriate analysis technique to that business (see 1b and 1c).
   b. Eleven business areas (see table on **page 54**), representing over 80% of our expected 2030 adjusted EBITDA, were identified as both providing a potentially significant financial contribution and facing primary transition risk drivers, and accordingly were subjected to the driver-based scenario analysis set out in steps 2a-2c below.
   c. The remaining business areas were taken forward to a simplified scenario analysis, per step 2d below.
2. **Scenario analysis:** We tested the financial impact of transition on all of bp's business areas in 2030 through either specific 'driver-based' scenario modelling (that includes 1.5°C and current policies), or by 'simplified' conservative scenario analysis, that modelled cases likely to be beyond these ranges.
   a. For the driver-based scenario analysis, we selected the primary transition risk driver(s) for each business area – the variable(s) from the WBCSD Scenario Catalogue representing what we consider to be the primary driver(s) of that business area's exposure to the energy transition. For each transition risk driver, we extracted the full range of 2030 outcomes within each scenario 'family'. Given the global nature of the transition risks and opportunities we have identified, we used the 'world' values in the Catalogue except for gas price (see table on **page 54**).
   b. By calibrating the WBCSD Scenario Catalogue 2030 scenarios to relevant business metrics underpinning our strategic planning (for example, oil price or EV demand/utilization), we modelled the impact of each variable, across the full range of scenarios and each scenario family, on the 2030 expected earnings (adjusted EBITDA) for the associated business area(s). For example, we applied an earnings rule of thumb deemed appropriate to the period in question to the deviation of oil prices in WBCSD versus our reference case price. This analysis was unmitigated (see 'Other key considerations').
   c. This enabled us to assess the potential for each scenario to materially impact group adjusted EBITDA in 2030 (and by implication associated cash flows), against the reference group business outlook. By modelling the specific business area within the reference group business outlook (described in step 1b above), its exposure to the most extreme range of the respective scenario could be assessed to identify which (if any) variables(s) and scenario(s) could have the potential to impact strategic resilience (as defined below) most materially, and as such, which business areas should be carried forward into a multi-year resilience assessment.
   d. For the simplified scenario analysis, we took a simpler conservative approach, by evaluating whether a scenario in which each business area's expected 2030 adjusted EBITDA is assumed to be reduced to zero – an outcome at least as detrimental to that business area's adjusted EBITDA as could reasonably be expected to result from ranges associated with the trajectory of each of the 1.5°C, 2°C or BAU scenario families – could have the potential to impact strategic resilience (as defined below) materially.
3. **Multi-year resilience test:** This step tested bp's resilience to the exposure of any sufficiently material business areas to downside scenarios that may have the potential to jeopardize the ability to generate surplus cash flow★ and a strong cash cover ratio and gearing level – financial metrics that were treated for the purposes of the analysis as representing financial evidence of delivery of bp's strategic financial priorities (see below). From step 2, in 2024, only the exposure to oil price was assessed as sufficiently material in this sense, and hence carried forward for multi-year resilience analysis. Our multi-year (2026-30) oil price resilience test considered sustained low oil prices consistent with the most extreme WBCSD Scenario Catalogue scenarios – interpolating between the minimum price for 2025 (the UN PRI Inevitable Policy Response Forecast Policy Scenario) at \$55.0/bbl, and the minimum for 2030 (the UN PRI Inevitable Policy Response Required Policy Scenario) at \$34.2/bbl (both 2022 \$ real). Other scenarios, from providers such as IEA and NGFS, formed part of the WBCSD data set, but indicated higher prices than the UN PRI cases used.

Other key considerations

- For the purposes of steps 2 and 3, we considered the resilience of our strategy to climate-related transition risk through the three lenses described on **page 51**. We defined the following as proxy indicators for these lenses:
  – Positive group surplus cash flow, to demonstrate whether after funding, among other things, capital spend within our disclosed capital frame (26 February 2025 Capital Markets Update) and a resilient dividend per ordinary share, sufficient surplus cash flow remains to maintain or reduce net debt and such that excess cash can be shared with investors through share buybacks over the period.
  – Healthy cash cover ratio and gearing★ as indicators of the ability to maintain a strong investment grade credit rating.

- For steps 2 and 3, we made the simplifying assumption that, aside from the driver being modelled, our strategy, operating model, cost basis, volumes, margins, sales proceeds and tax rates would remain unchanged out to 2030[a].
- There are a range of mitigations or actions that we might naturally be expected to experience (e.g. through deflation) or to take in response to external market, price and demand trends, including cost reductions, portfolio adjustments, distributions, capital reallocation or capital reductions within the frames set out in our strategy.
- For step 3, given we would seek to make use of opportunities to maintain our strategic flexibility in the face of the many uncertainties of the energy transition, our methodology retains the optionality in downside scenario modelling to apply some or all of these mitigations.
- The design of a strategic resilience analysis involves numerous methodological choices and assumptions – any one of which could reasonably have been different, leading to different outcomes. We have found value in conducting this analysis; however, we are mindful of the limitations to any such exercise and the highly qualified nature of any conclusions which may be drawn from it. The disclosures provided here should be read in conjunction with the rest of our strategic report, where we discuss how we have developed, and continue to evolve, our approach to strategy.
- As outlined above, we utilized our latest internal reference group business outlook as the basis against which resilience has been tested, as this is our latest deterministic view against which to model the transition sensitivities to 2030 and aligns to the strategic update provided to investors in February 2025. Alongside disclosed elements such as the capital frame range to 2030, this includes shaping assumptions such as future distribution and net debt management.
- Through conducting this analysis, we do not intend to imply or commit to a specific forward trajectory of usage of cash, beyond any disclosed in the investor update in February 2025 or other published strategy updates. While we cannot disclose, for confidentiality reasons, the detail of the deterministic case, the test assesses whether the resilience indicators in our reference group business outlook are impacted by the transition uncertainties tested. Further, by the nature of the timeframes considered, a variety of uncertainties exist around this deterministic case (including transition risk itself).
- Where rules of thumb have been applied, to convert variance in hydrocarbon price to variance in adjusted EBITDA, these are deemed appropriate to the period in question – i.e. they reflect the portfolio's price leverage over the period to 2030. Due to the evolution of bp's portfolio, these rules of thumb may diverge from any short-term rule of thumb that we publish.

WBCSD Scenario Catalogue family ranges for 2030 key transition variables

Business area		TCFD/WBCSD variable	BAU Min	BAU Max	Below 2°C Min	Below 2°C Max	1.5°C Min	1.5°C Max
Oil and natural gas production		Oil price[b] ($2022/bbl)	63.67	85.00	50.00	77.34	34.2	71.12
		Natural gas price[c] ($2022/mmbtu)	3.77	4.38	2.50	4.38	2.40	5.24
Refining	**– refined oil demand**	Primary energy demand for oil (% vs 2020)	-0.2	14.2	1.6	6.4	-18	-1
	– biojet demand	Final demand for liquid biofuels in aviation (EJ/yr)	0.16	0.5	0.16	1.01	0.25	1.51
Biogas		Biogas demand in road transport (EJ/yr)	0.00	0.19	0.01	0.29	0.00	0.35
bp bioenergy		Biofuel consumption in transport (EJ/yr)	0.84	6.05	0.84	7.08	1.45	7.12
EV charging		Final energy demand for electricity in road transport (EJ/yr)	3.02	6.97	3.86	6.90	3.64	7.08
Aviation fuel sales		Liquid fuel consumption in aviation (EJ/yr)	14.67	16.99	13.85	16.91	11.94	14.61
Conventional fuels retail		Final energy demand for liquid oil in road transport (EJ/yr)	75.09	81.65	74.35	76.82	59.00	73.41
Conventional fuels midstream								
Conventional road lubricants								
Renewables		Renewable capacity additions (GW vs 2020)	3,969	7,217	3,024	8,223	4,002	10,473
Hydrogen production		Hydrogen consumption (Mt/yr)	3.97	12.67	4.18	25.45	5.68	70.00

For the other business areas not shown above, we applied the generic scenario analysis methodology described in point 2d on **page 53**, thereby ensuring coverage of all of bp's business areas.

a For the purposes of resilience testing, *Castrol* is included in the underlying reference plan being assessed, pending the outcome of its strategic review.
b Oil price sensitivities have been applied to the oil and gas production portfolio that is linked to oil marker prices – as such it not only reflects oil production exposure, but also a proportion of bp's natural gas production that is contracted off oil marker prices.
c Gas prices shown reflect Henry Hub price ranges. Where available in the TCFD/WBCSD data sets Asian and UK gas price sensitivities have also been selected and compared to the Henry Hub sensitivity percentages with the maximum deviation selected and applied to the respective Asian and NBP rules of thumb for these parts of the gas portfolio, in order to provide the most conservative uncertainty range.

Metrics and targets

TCFD Recommendation:

Disclose the metrics and targets used to assess and manage relevant climate-related risks and opportunities where such information is material.

We present the principal group-wide metrics and targets used to assess and manage climate-related risks and opportunities in line with our strategy and risk management process below, with metrics and targets mapped to the most relevant of TCFD's cross-industry, climate-related metric categories (such as 'transition risks'). The metrics and targets themselves are disclosed at the most appropriate locations in this strategic report.

TCFD recommended disclosures – metrics and associated targets/goals

a) Disclose the metrics used by the organization to assess material climate-related risks and opportunities in line with its strategy and risk management process.	c) Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets.
Transition risks	
• Note 5 to Financial statements: Segmental analysis. Segment revenue (in table), **pages 167-171** • Estimated net proved reserves and production (net of royalties), **page 37** • Note 4 to Financial statements: Disposals and impairments, **page 164** • Note 8 to Financial statements: Impairment losses (in table), **page 172** • Oil and natural gas prices used for value-in-use impairment testing and recoverability of asset carrying values, **pages 152 and 256.**	Net zero operations★ (including methane), **page 38** Net zero sales★, **page 39**
Physical risks	
• Number of major operating sites in regions with high to extremely high water stress, **page 47** • Freshwater withdrawals and consumption at major operating sites in regions with high or extremely high water stress, **page 60**	Water, **page 60**
Climate-related opportunities	
• 2024 metrics, **page 9** (in table with **TCFD**) • Note 5 to Financial statements: Segmental analysis. Segment revenue (in table), **pages 167-171** • Renewables – installed capacity, developed to final investment decision and pipeline, **page 28**	Net zero operations (including methane), **page 38** Net zero sales, **page 39**
Capital deployment	
• Financial frame, **page 18** • Price assumptions, key investment appraisal assumptions, **page 20** (in table, indicated with **TCFD**) • Amount invested in transition, **page 39** • Additional information – capital expenditure by segment, **page 312** • Note 7 to Financial statements: expenditure on research and development (in table), **page 171** • Note 8 to Financial statements: exploration and evaluation costs (in table), **page 172**	Investment in non-oil and gas, **page 21** Transition investment, **page 39**
Internal carbon prices	
• Internal carbon price, **page 20**	
Remuneration	
• Directors' remuneration report metrics: operated carbon emissions, **page 96**	Incentivizing employees, **page 59**
b) Disclose Scope 1, Scope 2, and, if appropriate, Scope 3 greenhouse gas (GHG) emissions, and the related risks	
GHG emissions	
• Key performance indicators (relevant KPIs shown with **TCFD**), **page 14**[a] • Scope 1 and 2, in SECR table **page 40** • Ratio of Scope 1 and 2 emissions: gross production, in SECR table **page 41** • Scope 3 (related to category 11) emissions **page 39**[b] • TCFD: risks as described in Strategy A, **page 47** • Risk factors, **page 65** • A further breakdown of our GHG and energy data by business group is available in the *bp ESG Datasheet 2024* at **bp.com/ESG**.	Net zero operations (including methane), **page 38** Net zero sales, **page 39**

a These are our KPIs for the purposes of our disclosures pursuant to the UK CFD Regulations and Section 414CB (2A) (h) of the Companies Act 2006.
b In determining the Scope 3 emissions that are 'appropriate' to be disclosed for the purposes of this Recommended Disclosure, we have considered this term in the context of the recommendation to disclose the metrics and targets used to assess and manage relevant climate-related risks and opportunities. For 2024, the relevant target that we used in respect of Scope 3 emissions was bp's net zero production★ aim (aim 2), which was aligned to category 11 of Scope 3.

★ See glossary on **page 351**

Our approach to sustainability

Our approach to sustainability is built on strong foundations that guide the way we work and support our net zero, people and planet aims.

Safety comes first

At bp, safety comes first. We want to improve our safety performance and work towards our goal to eliminate fatalities, life-changing injuries and tier 1 process safety events.

We deeply regret the fatality and four life-changing injuries that occurred at bp in 2024. In October, an employee of our recently acquired bp bioenergy business in Brazil[a] was fatally injured during an operational activity. In May, a contractor in our wells business in Trinidad and Tobago and an employee at our TravelCenters of America business in the US[b] suffered life-changing injuries during manual activities. In September, at our *Thorntons* retail business in the US, two employees suffered life-changing injuries during an incident with a member of the public who was carrying a firearm.

We have offered our support to the employees and families affected. We want to learn from these incidents to help drive further improvements in safety.

Keeping people safe

We monitor and report on key workforce personal safety metrics in line with industry standards. We include both employees and contractors in our data.

In 2024 our recordable injury frequency (RIF) increased by 8.5% compared to 2023. bp businesses have identified underlying themes for these injuries and developed plans intended to help reduce then in the future.

In 2024 following the roll-out of International Association of Oil & Gas Producers' (IOGP) Life-Saving Rules to help improve safety performance, we started measuring their effectiveness in operational businesses that implemented them in 2023, and work continued to embed them in other operational businesses through safety inductions, team talks and control of work systems.

RIF key performance indicator, **page 14**

Driving safety

Driving continues to be one of the biggest personal safety risks we face at bp. In 2024 five severe vehicle accidents occurred, a decrease from seven in 2023. The number of kilometres driven fell by 11% over the same period.

	2024	2023	2022
Severe vehicle accident rate per million km driven	**0.022**	0.023	0.037

Our Operating Management System[c]

Our Operating Management System (OMS)★ provides a single framework for delivering safe, reliable and compliant operations. Our OMS sets out the way in which our businesses within our operational control around the world are expected to understand and manage their environmental and social impacts, including requirements on engaging with stakeholders who may be affected by our activities.

We review and amend these requirements from time to time to reflect our priorities. Any variations in the application of our OMS, in order to meet local regulations or circumstances, are subject to a governance process[c].

Our OMS requires each of bp's operating businesses to create and maintain its own OMS handbook, describing how it will carry out its local operating activities.

We use a 'three lines of defence' model to facilitate the effective management of all types of risk, including safety. The nature and extent of first, second and third lines of defence activities are based on the type and level of risk.

Preventing incidents

We carefully plan our operations with the aim of identifying potential hazards and having rigorous operating and maintenance practices applied by capable people to manage risks at every stage. We design our new facilities in line with process safety, good design and engineering principles. We track our process safety performance using industry-aligned metrics such as those found in the American Petroleum Institute recommended practice 754 and the IOGP recommended practice 456.

Our combined reported tier 1 and tier 2 process safety events★ (PSEs) have generally decreased over the last 12 years, apart from in 2019. Our total reported PSEs for 2024 was 38 compared to 39 in 2023. Although we reported more tier 2 PSEs, 35 compared with 30 in 2023, we reported our lowest number of tier 1 PSEs in 2024 as 3 (2023 9).

Our central health, safety, and environment incident investigations team investigates serious or complex incidents, which may include near misses, and we also use leading indicators, such as inspections and equipment tests, to monitor the strength of controls to prevent incidents.

In 2024 we made further progress in preventing and reducing oil spills. There were 96 oil spills, compared with 100 in 2023. Although portfolio changes may affect the overall baseline of our operations, our goal is still the elimination of tier 1 PSEs.

	2024	2023	2022
Tier 1 and tier 2 process safety events★	**38**	39	50
Oil spills – number	**96**	100	108
Oil spills – contained	**49**	52	57

a In October 2024 bp acquired the remaining 50% of bp Bunge Bioenergia. Shortly after the acquisition was completed, an incident occurred which resulted in a fatality. At the time of publication, bp bioenergy safety processes were still being integrated into bp's reporting processes, during an initial transition period for acquired businesses, and as such, this fatality is not included in reported fatality data for 2024.
b At the time of publication, during an initial transition period for these acquired businesses, Archaea Energy, TravelCenters of America, Lightsource bp and bp bioenergy safety reporting processes were still being integrated into bp's safety reporting processes and as such, their safety performance data is not included in reported data for 2024.
c For recently acquired businesses, there is typically a transition period while bp's operating standards, as set out in OMS, are integrated or aligned.

Emergency preparedness

The scale and geographical spread of our operations mean we must be prepared to respond to a range of possible disruptions, including emergency events. We maintain disaster recovery, crisis and business continuity management plans and work to build day-to-day response capabilities to support local management of incidents. We test our plans and preparedness through exercises that simulate real-life scenarios. In 2024 we conducted in the region of 25 exercises in countries including Indonesia and the US.

Security

We protect our people, assets and operations, and manage security through a threat-driven, risk-based approach. We continuously monitor threats from activism, civil unrest or political instability, terrorism, armed conflict, and criminal and cyber activity. Our 24-hour intelligence and response information centre in the UK monitors global security risk in real time. It helps us to assess the safety of our people and provide them with practical advice if there is an emergency.

Cyber security

The severity, sophistication and scale of cyber attacks continue to evolve. Increasing digitization, the emergence of new technology such as generative artificial intelligence, and reliance on IT systems and cloud platforms makes managing cyber risk a priority for many industries, including our own. Direct or collateral impact can come from a variety of cyber threat actors, including nation states, criminals, terrorists, hacktivists and insiders. As in previous years, we have experienced threats to the security of our digital systems and our barriers have worked well to mitigate and contain them to minimize any impact on our business.

We have a range of measures to manage this risk, including the use of cyber security policies and procedures, security protection tools, threat monitoring and event detection capabilities, and incident response plans. We conduct exercises to test our response to, and recovery from, cyber attacks. We collaborate closely with governments, law enforcement and industry peers to understand and respond to threats.

To encourage vigilance among our employees, our extensive cyber security training courses and awareness programmes provide regular education on a wide range of topics such as phishing and the correct classification and handling of our information. We also use a cyber barometer tool to empower individual risk mitigation.

How we manage risk, **page 61**

Additional disclosures – cyber security, **page 336**

Working with contractors

Through documents that help bridge our health, safety and environmental policies and those of our contractors, we define the way our OMS co-exists with systems used by our contractors to manage risk on a site. We conduct risk-based quality, technical, health, safety and security audits before awarding contracts. Once contractors start work, we continue to monitor their safety performance. Our OMS includes requirements and practices for working with contractors. Our standard model contracts include health, safety and security requirements. We expect and encourage our contractors and their employees to act in a way that is consistent with our code of conduct and take appropriate action if those expectations, or their contractual obligations are not met.

Our partners in joint arrangements

We monitor performance and how risk is managed in our joint arrangements★, whether we are the operator or not. In joint arrangements where we are the operator, our OMS, code of conduct and other policies apply.

We aim to report on aspects of our business where we are the operator – as we directly manage the performance of these operations.

Where we are not the operator, our OMS is available as a reference point for bp businesses when engaging with other operators and co-venturers. We have a group framework to assess and manage bp's exposure risks from our participation in these types of arrangements.

Where appropriate, we may seek to influence how risk is managed in arrangements where we are not the operator.

The people, culture and governance committee reviews workforce policies and practices and their alignment with bp's strategy, purpose, beliefs and culture, and conducts workforce engagement measures.

People, culture and governance committee report, **page 86**

Our people

Workforce by gender

	Male		Female		Female %	
As at 31 December 2024	**2024**	2023	**2024**	2023	**2024**	2023
Board directors	**5**	6	**6**	6	**55**	50
Leadership team	**5**	4	**5**	7	**50**	64
Group leaders	**186**	193	**100**	102	**35**	34
Subsidiary★ directors	**519**	384	**253**	174	**33**	31
All employees[a]	**62,000**	51,800	**38,300**	35,900	**38**	41

Number of employees

As at 31 December 2024	**2024**	2023	2022
Gas & low carbon energy	**6,500**	4,800	4,200
Oil production & operations	**9,200**	8,800	8,600
Customers & products[b]	**73,100**	63,400	44,700
Other businesses & corporate	**11,700**	10,800	10,100
Total[c]	**100,500**	87,800	67,600

a Some employees have not disclosed gender, therefore are not included in this total.
b This figure includes bp bioenergy, which bp took full ownership of in 2024.
c For 2024, this figure reflects new acquisitions and companies we have taken full ownership of including bp bioenergy and Lightsource bp.

Our culture

We want to build a culture that supports all of our employees and promotes inclusion, wellbeing and development.

Our culture frame, 'Who we are', defines what we stand for and is integrated into our code of conduct and our approach to diversity, equity and inclusion. We maintain oversight of our culture by measuring employee sentiment and encouraging employees to use our speak-up channels. Read more about the board's role in overseeing bp's culture on **page 87**.

Developing our people

Our people are crucial to delivering our purpose and strategy. We invest to ensure we have the right people with the right skills from diverse backgrounds, and we provide training, development and competitive rewards for them.

In 2024 bp employees collectively completed more than 1.2 million hours of formal learning (2023 1.3 million hours). This learning takes place within a development frame applicable to all employees. It covers safety, technical, leadership, digital and skills training relevant to our businesses. Our development offer also includes our mandatory curriculum focused on compliance with applicable laws and regulations as well as conformance with bp's internal standards.

Building an inclusive culture

Part of our people aim is to foster an inclusive culture with an employee workforce that reflects the communities where we work. To deliver our strategy we believe we need to capitalize on the diversity of perspectives, backgrounds, skills and experiences within our workforce.

Improving representation

We make all employment decisions based on merit without regard to gender, race, age, disability, or any other protected status.

In December 2024 five of the 10 positions in our leadership team were held by women. Our global ambition is to reach gender parity for the top levels of leadership (top 120 roles) by 2025 and parity for all executive-level employees (group leaders) by 2030. We also have a global ambition of 40% female representation for the next layer of senior leadership (senior-level leaders) by 2030. In 2024 35% of group leader roles were filled by women (2023 34%). We have made progress on our ambition to increase minority representation. In 2024 35% of our group leaders came from countries other than the UK and the US (2023 33%).

bp Gender and Ethnicity Pay Gap Report, **bp.com/ukgenderpaygap**

In line with UK reporting requirements, we disclose information against external targets on the representation of women and ethnic minorities on our board and executive management. Read more on diversity reporting and the Parker Review on **page 71**.

Composition of the board, **page 72**

Diversity reporting in line with the Listing Rules, **page 111**

Inclusion

To promote an inclusive culture, we support employee-run business resource groups (BRGs) in areas such as age diversity, social mobility, gender, ethnicity, and disability.

As well as bringing employees together, these groups contribute to our inclusive culture, provide a representative voice for employees and highlight and celebrate the achievements of different groups. Each group is sponsored by a member of the bp leadership team and open to all employees.

We aim to provide equal opportunity in recruitment, career development, promotion, training and reward for all employees – regardless of ethnicity, national origin, religion, gender, age, sexual orientation, marital status, disability or any other characteristic protected by applicable laws.

Supporting disabled employees

We continue to take steps to help improve the experience of the workplace for our neurodivergent employees and those with disabilities, offering:

- Inclusive recruitment training, disability and neurodiversity awareness sessions, as well as specific internships and apprenticeships.
- Access to assistive technology support (such as voice recognition software, screen readers and AI software) for all employees.
- Improved accessibility in communications, ensuring bp's brand visual standards are more accessible.

To help meet the requirements of our employees we work closely with our employee-led disability, neurodiversity and mental wellbeing BRGs.

If existing employees become disabled, our policy is to engage and use reasonable accommodations or adjustments to enable continued employment.

We have partnerships to help source talent, assist with research and training and support students with disabilities to build the skills they need to access the workplace. Our partners include the National Organization on Disability in the US, and the Business Disability Forum in the UK.

Employee engagement

Our managers hold team and one-to-one meetings with their team members, complemented by formal processes through works councils in parts of Europe.

We regularly communicate with employees on factors that affect bp's performance, and seek to maintain constructive relationships with labour unions formally representing our employees.

We monitor employee sentiment through our Pulse annual employee survey, which is sent to all eligible employees, and through our Pulse live survey, which is sent to a representative sample of employees weekly. In 2024 our overall engagement metric, employee engagement, decreased to 70%, in line with 2022 levels (2023 73%).

We will continue to develop engagement plans based on feedback from the annual and weekly surveys to help us deliver on safety, and meet our strategic objectives and our 2025 targets, focusing on three areas to drive improvement – psychological safety, competitiveness and understanding of our strategy and performance.

Our employee engagement key performance indicator, **page 17**

How the board engaged with the workforce, **page 78**

Workforce health and wellbeing

We include an employee wellbeing index in our Pulse annual employee survey and weekly Pulse live surveys. Results from 2024 showed that employee wellbeing increased to 73% (2023 72%).

We continued to take action to create workplaces where people can talk openly about mental health and get help if they need it, with campaigns focused on wellbeing and inclusion. We continued the roll-out of mental health training targeted at group leaders, to progress our 2025 aim to train 100% of leaders on key mental health challenges.

Linking remuneration to sustainability TCFD

Our annual bonus for all eligible employees[a], including the bp leadership team, has been linked to a sustainability measure since 2019.

The bonus scorecard for 2025 against which our eligible employees are measured incentivizes them through three themes: safety and sustainability (30%, of which sustainability makes up 15%); operational performance (15%); and financial performance (55%). For 2025 our sustainability measure is linked to our operated carbon emissions. This measure covers Scope 1 and 2 emissions reported as part of our net zero operations★ aim (see **page 38**).

Our 2022-24 long-term incentive plan scorecard also linked to our operated carbon emissions performance and, for group leaders[b], two social measures were included.

As with the bonus scorecard, for 2025-27 we use an absolute percentage reduction in operational emissions against our 2019 baseline as the basis for measuring progress against our net zero operations aim in our long-term scorecard.

Directors' remuneration report, **page 88**

Share ownership

We encourage employee share ownership and have a number of employee share plans in place. For example, we operate a ShareMatch plan, matching bp shares purchased by our employees. We also make annual share awards as part of our total reward package all for senior and mid-level employees globally, and a portion of our more junior professional grade employees.

Ethics and compliance

Our code of conduct

Our code sets standards and expectations for how we do the right thing and empowers our employees to speak up without fear of retaliation. It is the foundation of 'Who we are', our culture frame and puts safety first. Together with our Safety Leadership Principles and OMS★, our code helps us make safe and ethical decisions, act responsibly, comply with applicable laws and deliver on our sustainability frame.

Our code applies to all bp employees, officers and board members[c]. Regular mandatory training and communications help employees understand how to apply our code and how to raise questions or concerns.

All bp employees are required to confirm annually that they have read and understand our code and complied with its principles. We expect and encourage all our contractors and their employees to act in ways that are consistent with it.

Any concerns or enquiries can be raised through multiple speak-up channels. These include line managers, senior leaders[d], and contacts in our people & culture, ethics & compliance or legal teams. We also have a confidential global helpline, OpenTalk. It is available for employees, the wider workforce, communities, business partners and other stakeholders and can be accessed all day, every day by telephone or internet and in 75 languages. In most locations, anyone has the right to contact OpenTalk anonymously except where this is prohibited by law.

Any instances where we believe individuals have fallen short of our expectations, set out in our beliefs, 'Who we are' and our code of conduct, are taken very seriously and, where appropriate, a formal investigation is carried out.

We may take action in response to reported concerns to help proactively mitigate issues around misconduct. We follow a defined disciplinary process and will issue sanctions where appropriate. These may include measures ranging from coaching or training, formal reprimands to dismissal.

We received more than 2,800 concerns or enquiries through these channels in 2024 (2023 2,250). In 2024 around 250 separations resulted from non-conformance with our code or unethical behaviour[e].

As in 2023 the most frequently raised concerns in 2024 related to bullying, harassment and discrimination, with these accounting for around 60% of all concerns. The second most common concerns related to health, safety, security and environment.

bp.com/codeofconduct

Anti-bribery and corruption

We operate in parts of the world where bribery and corruption present a high risk, so it is important that we engage with our employees, contractors, suppliers and others to emphasize our commitment to ethical and compliant operations is unwavering.

Our code of conduct explicitly prohibits engaging in bribery or corruption in any form.

Our group-wide anti-bribery and corruption policies and procedures include measures and guidance to assess risks, understand relevant laws and report concerns. They apply to all bp-operated businesses.

We provide appropriate training including for those employees in locations or roles assessed to be at a higher risk of bribery and corruption.

In 2024 around 5,900 employees completed anti-bribery and corruption training as part of our ethics and compliance risk-based learning. This is lower than the 10,500 employees trained in 2023, due to the rolling cadence we use to assign training.

We also conduct anti-bribery compliance audits on selected suppliers to assess their conformance with our anti-bribery and corruption contractual requirements. We take corrective action with suppliers and business partners who fail to meet our expectations, which may include terminating contracts. In 2024 we issued 32 ABC supplier audit reports (2023 31).

Political donations and activity

We prohibit the use of bp funds or resources to support any political candidate or party. We recognize the rights of our employees to participate in the political process and these rights are governed by the applicable laws in the countries where we operate. Our stance on political activity is set out in the bp code of conduct.

In the US we provide administrative support for the bp employee political action committee (PAC) – a non-partisan, employee-led committee that encourages voluntary employee participation in the political process. The bp employee PAC is governed by a board of directors and administrative by-laws. All contributions made by the bp employee PAC are weighed against its criteria for candidate support and reviewed for legal compliance before funds are sent to the recipients requested by our employees, and are publicly reported in accordance with US election laws. Contributions made by the PAC are from employee contributions and not bp funds.

Tax transparency

Our code of conduct informs the responsible approach we take to managing taxes. We have adopted the B Team responsible tax principles and we engage in open and constructive dialogue with governments and tax authorities.

We comply with the tax legislation of the countries in which we operate and we do not tolerate the facilitation of tax evasion by people who act for or on behalf of bp.

We are committed to transparency around our tax principles and the taxes we pay. We paid $10.6 billion in corporate income and production taxes to governments in 2024 (2023 $11.9 billion).

bp Tax Report, **bp.com/tax**

Key

TCFD	TCFD Recommendations and Recommended Disclosures

a The number of employees eligible for a cash bonus in 2024 was around 38,000.
b Group leaders are our most senior leaders. Their roles include operational, functional and regional leadership.
c For recently acquired businesses, there is typically a transition period while bp's ethics and compliance standards, as required in our code, are integrated or aligned.
d Senior leaders are the leadership tier below group leaders. They typically manage larger teams or are recognized as technical or functional experts.
e This total excludes exits of contractors, suppliers and vendors.

Trade associations

Trade associations play a key role in fostering collaboration, sharing learning and bringing stakeholders together. We periodically assess the alignment of key associations with our position on climate. In 2024 we reviewed 36 of our most significant trade associations memberships. We found that 29 associations aligned with our climate positions, and seven were 'partially aligned'. Our priority is to influence within trade associations, but we may publicly dissent or resign our membership if there is material misalignment on high-priority issues.

bp.com/tradeassociations

People and planet.

Improving people's lives

We want to support employees our wider workforce and local communities.

People

Our aim is to support our employees and local communities through the energy transition by:

- Equipping employees with skills that can improve their access to opportunities in the energy transition.
- Developing targeted just transition plans[a] for select assets or regions, that help manage potential impacts on and opportunities for people as we transition.
- Fostering an inclusive culture with an employee workforce that reflects the communities where we work (read more on **page 58**).

We support the goals of the Paris Agreement, which recognize the importance of a just transition – one that delivers decent work, quality jobs and supports the livelihoods of local communities. We report on our work to equip employees with the skills they need through the energy transition and how we are helping enable a just transition in the *bp Sustainability Report 2024*.

Human rights

We believe everyone deserves to be treated with fairness, respect and dignity. We strive to conduct our business in a responsible way, respecting the human rights of our workforce and those living in communities potentially affected by our activities.

We set out our commitments in our human rights policy and code of conduct. Our policy aligns with the UN Guiding Principles on Business and Human Rights.

It is underpinned by the International Bill of Human Rights and the International Labour Organization's Declaration on Fundamental Principles and Rights at Work, including its core conventions.

To support our teams, we provide human rights training and other awareness-raising activities. In 2024 this included training for our procurement teams to identify suppliers in high-risk goods and high-risk services categories.

bp.com/humanrights

Caring for the planet

We want to make a positive difference to the environment in which we operate.

Biodiversity

We understand international concern regarding the global decline in biodiversity and recognize that our businesses can have impacts and dependencies on nature.

We aim to support biodiversity where we operate[b], by:

- Aiming to achieve a net positive impact (NPI) on all new in-scope[c] projects.
- Implementing biodiversity enhancement plans at our major operating sites.
- Collaborating with others to support selected biodiversity restoration projects.

Building on the work we did in 2022 to finalize our NPI methodology for use on new, in-scope projects, we have made consistent progress over the past few years in our work to apply it. By the end of 2024 seven of our projects were developing NPI plans.

bp.com/biodiversity

Water

We aim to reduce our net freshwater use in stressed catchments where we operate[b], by:

- Being more efficient with freshwater use in our operations.
- Collaborating with others to replenish freshwater in stressed[d] catchments.

We anticipate that by 2028, our freshwater withdrawal in stressed catchments will be covered by freshwater management plans.

To understand our water-related challenges, we review water impacts, risks and opportunities at our operating sites. These reviews consider the quantity and quality of water used as well as any applicable regulatory requirements.

Our water consumption in 2024

We saw a 15% fall in freshwater withdrawals (excluding once through cooling water)[e] and a 17% fall in freshwater consumption, compared with our 2020 baseline[f]. Reductions in 2024 were achieved through the use of non-freshwater sources in bpx energy Eagle Ford, US.

At our major operating sites, 11% (2023 73%) of our total freshwater withdrawals and 20% (2023 36%) of freshwater consumption were from regions with high or extremely high water stress in 2024. This is significantly lower than 2023 due to two changes. One refinery is in a region of medium-high water stress and therefore no longer reaches the threshold. Separately, we reviewed the status of two other refineries using site-specific local data sources in 2024, this resulted in one of those refineries being reclassified as not being in an area of high water stress, the other reviewed refinery remained in an area of high water stress.

Air emissions

We monitor our air emissions – sulphur oxides, nitrogen oxides and non-methane hydrocarbons – and, where possible, put measures in place to reduce the potential impact of our operational activities on local communities and the environment. In 2024 our total air emissions were 9% lower compared to 2023.

bp.com/ESGdata

a We will work to develop just transition plans with input from potentially affected stakeholders to help manage social risks and opportunities.
b At our new in-scope bp-operated projects and major operating sites.
c New bp-operated in-scope projects where planned activities have the potential for significant direct impacts on biodiversity are required to develop NPI action plans for those activities.
d The threshold bp is now using for stress is based on a water stress level of 'high' or above, as defined by the WRI Aqueduct Water Atlas. bp determines areas of water stress using either the WRI Aqueduct Water Atlas or using site-specific local data sources.
e Following an update in 2024 to the basis for calculating freshwater withdrawal to align with the basis for calculating freshwater consumption and improve clarity and consistency, metrics based on freshwater withdrawal data have been restated for the years 2020-2023 to reflect the exclusion of once through cooling water, including the 2020 baseline.
f The restated 2020 baseline for freshwater withdrawal is 96.4 million m^3 per year and for freshwater consumption is 55.9 million m^3 per year.

How we manage risk and risk factors

How we manage risk

bp manages, monitors and reports on the principal risks and uncertainties we have identified that can impact our ability to deliver our strategy. These are described in Risk factors on **page 65**.

bp's system of internal control is a holistic set of internal controls that includes policies, processes, management systems, organizational structures, culture and standards of conduct employed to manage bp's business and associated risks.

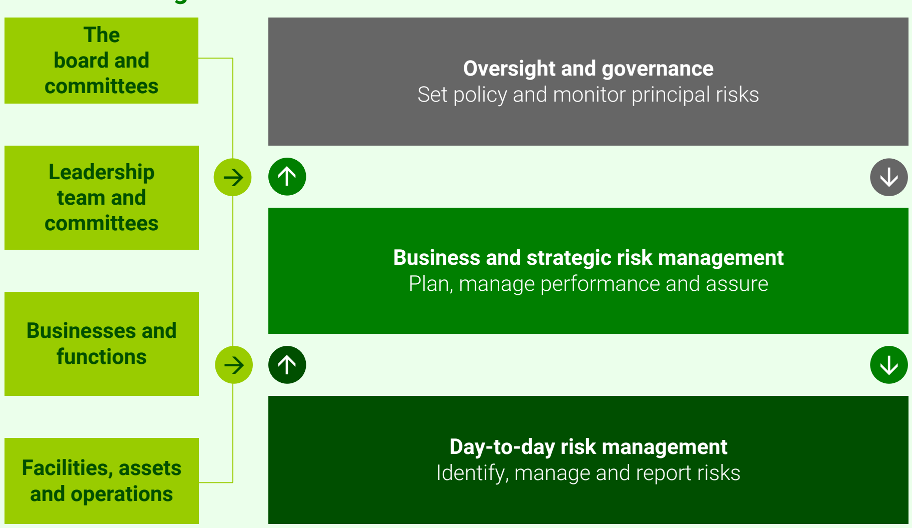
bp's risk management system

bp's risk management system and risk management policy are designed to provide a consistent and clear framework for managing and reporting risks from the group's business activities and operations to management and to the board.

The system seeks to avoid incidents and enhance business outcomes by allowing us to:

- Understand the risk environment, identify the specific risks and assess the potential exposure for bp.
- Determine how best to deal with these risks to manage overall potential exposure.
- Manage the identified risks in appropriate ways.
- Monitor and seek assurance over the effectiveness of the management of these risks and intervene for improvement where necessary.
- Report up the management chain and to the board on a periodic basis on how principal risks are being managed, monitored and assured, with any identified enhancements that are being made.

Our risk management activities



Risk oversight and governance

Our key risk oversight and governance committees include:

Board and committees

- bp board.
- Audit committee.
- Safety and sustainability committee.
- Remuneration committee.
- People, culture and governance committee.

Leadership team and committees

- Leadership team meeting – for oversight and for strategic and commercial risks.
- Group operations risk committee – for health, safety, security, environment and operations integrity risks.
- Group financial risk committee – for finance, treasury, trading and cyber risks.
- Group disclosure committee – for financial and non-financial reporting risks.
- People and culture committee – for employee risks.
- Group ethics and compliance committee – for legal and regulatory compliance and ethics risks.
- Group sustainability committee – for non-operational sustainability risks.
- Resource commitment meeting – for investment decision risks.
- bp quarterly internal audit meeting – for assurance on the oversight of bp's principal risks.

bp governance framework, **page 75**, board activities, **page 76**, committee reports, **pages 80-90** and risk management and internal control, **page 112.**

Acquired businesses

Integration plans are developed to transition acquired businesses into bp's system of internal control and risk management framework, over an appropriate timeframe.

★ See glossary on **page 351**

Day-to-day risk management

Management and employees at our facilities, assets, and within our businesses (including supply, trading and shipping) and functions seek to identify and manage risk, promoting safe, compliant and reliable operations. bp requirements, which take into account applicable laws and regulations, underpin the practical plans developed to help reduce risk and deliver safe, compliant and reliable operations as well as greater efficiency and sustainable financial results.

Business and strategic risk management

Our businesses and functions integrate risk management into key business processes such as strategy, planning, performance management, resource and capital allocation and project appraisal. They do this by using a standard framework for collating risk data, assessing risk management activities, making further improvements and in connection with planning new activities.

Oversight and governance

Throughout 2024, management, the leadership team, the board and relevant committees provided oversight of how principal risks to bp were identified, assessed and managed. They supported appropriate governance of risk management including having relevant policies in place to help manage risks.

Such oversight may include internal audit reports, group risk reports and reviews of the outcomes of business processes including strategy, planning and resource and capital allocation. bp's group risk team analyses the group's risk profile and maintains the group's risk management system. bp's internal audit team provides independent assurance to the chief executive and board as to whether the group's system of internal control is adequately designed and operating effectively to respond appropriately to the risks that are significant to bp.

Risk management processes

We aim for a consistent basis of measuring risk to:

- Establish a common understanding of risks on a like-for-like basis, taking into account potential impact and likelihood.
- Report risks and their management to the appropriate levels of the organization.
- Inform prioritization of specific risk management activities and resource allocation.

bp's risk management policy sets out requirements for the group to follow. These requirements support the consideration of three risk types:

- Strategic and commercial.
- Safety and operational.
- Compliance and control.

Risk identification – businesses and functions identify risks across the risk types. Risks are identified on an ongoing basis – this can be done using a range of approaches including workshops, subject-matter expertise, hazard identification processes and engineering requirements.

Risk assessment – identified risks are assessed for potential impact and likelihood across a number of criteria, including health and safety, environmental, financial and non-financial (includes reputation and regulatory impact levels).

This aims to provide a consistent basis for the evaluation of potential impact and likelihood, facilitating a comparison across different risks.

Risk management and monitoring – risk management activities are prioritized where improvements are needed based on a number of factors, including the risk assessment, strength of existing risk management measures, strategy and plans and legal and regulatory requirements.

Risk management measures, including mitigations, are identified for each risk and monitored to the extent considered appropriate. To support leadership oversight of decisions relating to risk management, the appropriate organizational level (EVP, SVP, VP) are notified of risks and asked to endorse risk management plans, depending on the assessed potential impact and likelihood.

As part of bp's annual planning process, the leadership team and the board review the group's principal risks and uncertainties. These may be updated during the year in response to changes in internal and external circumstances.

There can be no certainty that our risk management activities will mitigate or prevent these, or other risks, from occurring. Further details of the principal risks and uncertainties faced are set out in Risk factors on **page 65**.

Our risk profile

The nature of our business operations is long term, resulting in many of our risks being enduring in nature. However, risks can develop and evolve over time and their potential impact or likelihood may vary in response to internal and external events. These may include emerging risks which are considered through existing processes, including emerging risk communications to the board, bp's risk management system, *bp Energy Outlook*, bp's technology-related news and insights publications, ongoing emerging technology scanning and group strategic reviews.

We describe above how risks are managed. The following section provides examples of the particular risk management activities for each of bp's principal risks.

Strategic and commercial risks

Prices and markets

Our financial performance is impacted by fluctuating prices of oil, gas and refined products, technological change, climate policies and regulations, exchange rate fluctuations, and the general macroeconomic outlook.

Our strategy is designed to accommodate a range of scenarios and be resilient to the volatility in the energy markets. This is supported through a diversified portfolio, a strong balance sheet and operating within a resilient and disciplined financial frame. We test our investment and project development costs against a range of pricing and exchange assumptions.

Accessing and progressing hydrocarbon resources and low carbon opportunities

Inability to access and progress hydrocarbon resources and low carbon opportunities could adversely affect delivery of our strategy.

For hydrocarbon resources our subsurface team is accountable for the delivery of high-value, carbon-efficient resources to deliver predictable and reliable investments today, as well as the long-term renewal of our hydrocarbon resources. Additionally, the subsurface team partners with technology to prioritize development needs for the future. Our gas & low carbon energy business is accountable for the delivery of many of our low carbon opportunities through both organic and inorganic growth. This includes the development of wind, solar, hydrogen and carbon capture, use and storage businesses.

Major project delivery

Failure to invest in the best opportunities or deliver major projects★ successfully could adversely affect our financial performance.

We seek to manage the risk through our projects organization which exists to assess, develop and execute projects across bp. The organization contains capability which includes the centre of expertise for appraisal and optimization, expertise to manage the design and build of projects and integrates with our businesses and functions to ensure project objectives are met. The projects organization utilises a major projects common process.

Geopolitical

The diverse locations of our business activities and operations around the world expose us to a wide range of political developments and consequent changes to the economic and operating environment. Geopolitical risk is inherent to many regions in which we operate, and heightened political or social tensions or changes in key relationships could adversely affect the group.

We seek to manage this risk at multiple levels, through:

- Identifying macro-level geopolitical trends in the geopolitical advisory council.
- Providing a clear focal point for political risk management.
- Monitoring how geopolitical trends create risk at the country level through changes to our baseline threat assessments.

More broadly, we manage the risk on a day-to-day basis through the development and maintenance of relationships with governments and stakeholders, and by being trusted partners in each country and region. In addition, we closely monitor events and implement risk mitigation plans where deemed appropriate.

Liquidity, financial capacity and financial, including credit, exposure

External market conditions can impact our financial performance. Supply and demand and the prices achieved for our products can be affected by a wide range of factors including political developments, interest rates, consumer preferences for low carbon energy, global economic conditions, access to capital markets and the influence of OPEC+.

We seek to manage this risk through bp's diversified portfolio, our financial frame, liquidity stress testing, maintaining a significant cash buffer, liquidity facilities, regular reviews of market conditions and our planning and investment processes.

Energy markets, **page 7**
Liquidity and capital resources, **page 316**
Liquidity, financial capacity and financial, including credit, exposure, **page 65**

Joint arrangements★ and contractors

Varying levels of control over the standards, operations and compliance of our partners including non-operated joint ventures (NOJVs), contractors and sub-contractors could result in legal liability and reputational damage.

bp's exposure in NOJVs is primarily managed by the NOJV-facing business team in the business or entity where ownership of bp's interest in the NOJV sits.

Support, verification and assurance are provided by the NOJV solutions team, safety and operational risk assurance, ethics & compliance functional assurance and group internal audit to drive a focused, deliberate and systematic approach to the set-up and management of bp's interests and exposure in NOJVs.

Our relationships with contractors are managed through the bp procurement processes with appropriate requirements incorporated into contractual arrangements.

Digital infrastructure, cyber security and data protection

Both targeted and indiscriminate threats to the security and resilience of our digital infrastructure and those of third parties continue to evolve rapidly and are increasingly prevalent across industries worldwide.

We seek to manage this risk through a range of measures, which include alignment to the National Institute of Standards and Technology Cyber Security Framework 2.0, cyber security, data protection and artificial intelligence standards, security protection tools, ongoing detection and monitoring of threats and testing of digital response and recovery procedures. We collaborate with governments, law enforcement agencies and industry peers to understand and respond to new and emerging cyber threats.

We build awareness with our employees, share information on incidents with leadership for continuous learning, and conduct annual cyber training and regular exercises, including with the leadership team, to test response and recovery procedures. For further detail on cyber security disclosures see **page 336**.

Climate change and the transition to a lower carbon economy

Developments in policy, law, regulation, technology and markets, including societal and investor sentiment, related to the issue of climate change and the transition to a lower carbon economy could increase costs, reduce revenues, constrain our operations and affect our business plans and financial performance.

Risks associated with climate change and the transition to a lower carbon economy impact many elements of our strategy and, as such, these risks are managed through key business processes including setting the bp strategy and annual plan, capital allocation and investment decisions. The outputs of these key business processes are reviewed in line with the cadence of these activities. See **page 48** for more information on how transition risks and opportunities are managed.

Competition

Inability to remain efficient, maintain a high-quality portfolio of assets and innovate could negatively impact delivery of our strategy in a highly competitive market.

We seek to manage this risk through our strategy, sustainability and ventures function by providing external insights on the economic, energy, market and competitive environment. These insights are used to help define a resilient strategy for bp, including decisions related to portfolio, business development and resource allocation. The ventures team provides commercial innovation capacity that allows us to build new businesses.

Talent and capability

Inability to attract, develop and retain people with necessary skills, capabilities could negatively impact delivery of our strategy.

Our people, culture and communications team's responsibilities include talent activity for bp globally, including hiring, development, succession planning, and embedding of bp's 'Who we are' culture frame. They help to ensure that the right talent and people capability are in place, using local market intelligence, people analytics and insights to underpin our strategic workforce planning. See **page 57** for more information.

★ See glossary on **page 351**

Crisis management and business continuity

Failure to address an incident effectively could potentially disrupt our business or exacerbate the legal, financial or operational impacts of the crisis event.

Incidents that could potentially disrupt our business are addressed using emergency response and business continuity plans which are mandated through our policies. We use internationally recognized incident command structures, and for significant events business support teams and executive support teams are established to provide oversight and management. In addition, we provide a trained group of crisis professionals and niche expertise for deployment across bp through our mutual response team.

Insurance

Our insurance strategy could expose the group to material uninsured losses.

Our insurance team is accountable for aligning our insurance approach with bp's strategy and engaging with the businesses and functions to determine the appropriate level of insurance. We retain in-house expertise and partner with insurance industry leaders. Our captive insurance companies are regulated within the jurisdictions in which they operate.

Safety and operational risks

Process safety, personal safety and environmental risks

Exposure to a wide range of health, safety and environmental risks could cause harm to people, the environment and our assets and result in regulatory action, legal liability, business interruption, increased costs, damage to our reputation and potentially denial of our licence to operate.

Our Operating Management System (OMS)★ helps us manage these risks and drive performance improvements. It sets out the standards and requirements which govern key risk management activities such as inspection, maintenance, testing, business continuity and crisis response planning and competency development. In addition, we conduct our drilling activity through a wells organization in order to promote a consistent approach for designing, constructing and managing wells.

Drilling and production

Challenging operational environments and other uncertainties could impact drilling and production activities.

Our production and operations business group brings together all our hydrocarbon operations and our distinctive capabilities in one place to safely deliver competitive returns. The functions, in particular wells and production, are accountable for safety, risk, quality and operational delivery. They execute capital and operational activity and manage associated expenditure.

Security

Hostile acts such as terrorism, activism, insider acts or piracy could harm our people and disrupt our operations. We monitor for emerging threats and vulnerabilities to manage our physical and information security.

Our intelligence, security and crisis management teams provide strategic and operational risk management to our businesses through a network of regional security managers who provide front-line risk management as well as conduct assurance activities through a team independent of the business.

We continue to monitor threats globally and maintain disaster recovery, crisis and business continuity management plans.

Product quality

Supplying customers with off-specification products could damage our reputation, lead to regulatory action and legal liability, and impact our financial performance.

bp's product quality policy is aligned with our OMS and sets requirements for our business to meet specifications and applicable legal and regulatory requirements.

Compliance and control risks

Ethical misconduct and legal or regulatory non-compliance

Ethical misconduct or breaches of applicable laws or regulations could damage our reputation, result in litigation, regulatory action and penalties, adversely affect results and shareholder value, and potentially affect our licence to operate.

Our code of conduct, the foundation of 'Who we are', is applicable to all employees and central to managing this risk. Additionally, we have various group requirements and training covering areas such as anti-bribery and corruption, anti-money laundering, competition/anti-trust law, data privacy and international trade regulations. We offer an independent confidential helpline, OpenTalk, for employees, contractors and other third parties with the option to raise concerns anonymously.

Regulation

Changes in the law and regulation could increase costs, constrain our operations and affect our strategy, business plans and financial performance.

Our businesses and functions all seek to identify, assess and manage legal and regulatory risks relevant to bp's operations, strategy, business plans and financial performance. To support this work, we seek to develop co-operative relationships with governmental authorities in line with our code of conduct, to allow appropriate focus on areas of potential risk or uncertainty, while also protecting bp's interests within the law.

Trading and treasury trading activities

In the normal course of business, we are subject to risks around our trading activities which could arise from shortcomings or failures in our systems, risk management methodology, internal control processes or employee conduct.

We have specific operating standards and control processes to manage these risks, including guidelines specific to trading, and seek to monitor compliance through our dedicated compliance teams. We also seek to maintain a positive and collaborative relationship with regulators and the industry at large.

Reporting

Failure to accurately report our data could lead to regulatory action, legal liability and reputational damage.

Our accounting reporting and control team provides assurance of the control environment and is accountable for building control and compliance of finance processes and digital systems.

Risk factors

The risks discussed below, separately or in combination, could have a material adverse effect on the implementation of our strategy, business, financial performance, results of operations, cash flow, liquidity, prospects, shareholder value and returns and reputation.

Strategic and commercial risks

Prices and markets: our financial performance is impacted by fluctuating prices of oil, gas and refined products, technological change, climate policies and regulations, exchange rate fluctuations, and the general macroeconomic outlook.

Oil, gas and product prices are subject to international supply and demand and margins can be volatile.

Political developments, fluctuations to the supply of either oil or natural gas or to alternative low carbon energy sources, technological change, global economic conditions, public health situations (including the outbreak of an epidemic or pandemic), the introduction of new (or amendment to existing) carbon costs and the influence of OPEC+ can impact supply and demand and prices for our products (including low carbon investments).

Decreases in the price of energy outputs we produce could have an adverse effect on revenue, margins, profitability and cash flows. If these reductions are significant or for a prolonged period, we may have to write down assets and reassess the viability of certain projects, which may impact future cash flows, profit, capital expenditure★, the ability to work within our financial frame and maintain our long-term investment programme. Conversely, an increase in the prices of the energy outputs we produce may not improve margin performance as there could be increased fiscal take, cost inflation and more onerous terms for access to resources. The profitability of our refining activities can be volatile, with periodic oversupply or supply tightness in regional markets and fluctuations in demand.

Exchange rate fluctuations can create currency exposures and impact underlying costs and revenues. Crude oil prices are generally set in US dollars, while products vary in currency. Many of our major project★ development costs are denominated in local currencies, which may be subject to fluctuations against the US dollar.

Accessing and progressing hydrocarbon resources and low carbon opportunities: inability to access and progress hydrocarbon resources and low carbon opportunities could adversely affect delivery of our strategy.

Delivery of our strategy depends partly on our ability to progress hydrocarbon resources from our existing portfolio and access new resources. Our ability to progress upstream★ resources and develop technologies at a level in line with our strategic outlook for hydrocarbon production could impact our future production and financial performance. Furthermore, our ability to access low carbon opportunities and the commercial terms associated with those opportunities could impact our financial performance while moving at pace with society and its changing wants and needs.

Our strategy, **page 8**

Major project delivery: failure to invest in the best opportunities or deliver major projects successfully could adversely affect our financial performance.

We face challenges in developing major projects, particularly in geographically and technically challenging areas. Poor investment choice, efficiency or delivery, inflation, supply chain, or operational challenges at any major project that underpins production or production growth, could adversely affect our financial performance.

Geopolitical: exposure to a range of political developments and consequent changes to the operating and regulatory environment could cause business disruption.

We operate and may seek new opportunities in countries, regions and cities where political, economic and social transition may take place.

Political instability, changes to the regulatory environment or taxation, international trade disputes and barriers to free trade, international sanctions, expropriation or nationalization of property, civil strife, strikes, insurrections, acts of terrorism, acts of war and public health situations (including the outbreak of an epidemic or pandemic) may disrupt or curtail our operations, business activities or investments.

These may in turn cause production to decline, limit our ability to pursue new opportunities, affect the recoverability of our assets and our related earnings and cash flow or cause us to incur additional costs, particularly due to the long-term nature of many of our projects and significant capital expenditure required.

Trade restrictions, international sanctions or any other actions taken by governmental authorities or other relevant persons have had and could continue to have an impact on global energy supply and demand, market volatility and the prices of oil, gas and products.

Liquidity, financial capacity and financial, including credit, exposure: failure to work within our financial frame could impact our ability to operate and result in financial loss.

Trade and other receivables, including overdue receivables, may not be recovered, divestments may not be successfully completed and a substantial and unexpected cash call or funding request could disrupt our financial frame or overwhelm our ability to meet our obligations.

An event such as a significant operational incident, legal proceedings or a geopolitical event in an area where we have significant activities, could reduce our financial liquidity and our credit ratings. Credit rating downgrades could potentially increase financing costs and limit access to financing or engagement in our trading activities on acceptable terms, which could put pressure on the group's liquidity.

They could also potentially require the company to review the funding arrangements with the bp pension trustees. In the event of extended constraints on our ability to obtain financing, we could be required to reduce capital expenditure or increase asset disposals in order to provide additional liquidity.

Liquidity and capital resources, **page 316**
Financial statements – **Note 29**

Joint arrangements★ and contractors: varying levels of control over the standards, operations and compliance of our partners, including non-operated joint ventures (NOJVs), contractors and sub-contractors could result in legal liability and reputational damage.

We conduct many of our activities through joint arrangements, partners or with contractors and sub-contractors where we may have limited influence and control over the performance of such activities.

Our partners and contractors are responsible for the adequacy of their resources and capabilities. If these are found to be lacking, there may be financial, reputational, operational or safety exposures for bp. Should an incident occur in an activity that bp participates in, our partners and contractors may be unable or unwilling to fully compensate us against costs we may incur on their behalf or on behalf of the arrangement. Where we do not have operational control of a joint arrangement or direct oversight of contractor activity, we may still be pursued by regulators or claimants, and may still be the focus for interest groups or media attention in the event of an incident.

Digital infrastructure, cyber security and data protection: breach or failure of our or third parties' digital infrastructure or cyber security, including loss or misuse of sensitive information could damage our operations, increase costs and damage our reputation.

The energy industry is subject to fast-evolving risks, including ransomware, from cyber threat actors, including nation states, criminals, terrorists, hacktivists and insiders. Current geopolitical factors have increased these risks. There is also growing regulation around data protection and data privacy, critical national infrastructure and the evolving opportunities and threats from artificial intelligence. A breach or failure of our or third parties' digital infrastructure – including control systems – due to breaches of our cyber defences, or those of third parties, negligence, intentional misconduct or other reasons, could seriously disrupt our operations. This could result in the loss or misuse of data or sensitive information, including employees' and customers' personal data, injury to people, disruption to our business, harm to the environment or our assets, legal or regulatory breaches, legal liability and significant costs including fines, cost of remediation or reputational consequences. Furthermore, the rapid detection of attempts to gain unauthorized access to our digital infrastructure, often through the use of sophisticated and co-ordinated means, is a challenge and any delay or failure to detect could compound these potential harms.

Cyber security disclosures, **page 336**

Climate change and the transition to a lower carbon economy: developments in policy, law, regulation, technology and markets, including societal and investor sentiment, related to the issue of climate change and the transition to a lower carbon economy could increase costs, reduce revenues, constrain our operations and affect our business plans and financial performance.

Laws, regulations, policies, obligations, government actions, social attitudes and customer preferences relating to climate change and the transition to a lower carbon economy, including the pace of change to any of these factors, and also the pace of the transition itself, could have adverse impacts on our business including on our access to and realization of competitive opportunities, a decline in demand for, or constraints on our ability to sell certain products, constraints on production and supply, adverse litigation and regulatory or litigation outcomes, increased costs from compliance and increased provisions for environmental and legal liabilities.

Investor preferences and sentiment are influenced by environmental, social and governance (ESG) considerations including climate change and the transition to a lower carbon economy. Changes in those preferences and sentiment could affect our access to capital markets and our attractiveness to potential investors, potentially resulting in reduced access to financing, increased financing costs and impacts upon our business plans and financial performance.

Technological improvements or innovations that support the transition to a lower carbon economy, and customer preferences or regulatory incentives that alter fuel or power choices, could impact demand for our products (including low carbon energy).

Depending on the nature and speed of any such changes and our response, these changes could increase costs, reduce our profitability, reduce demand for certain products, limit our access to new opportunities, require us to write down certain assets or curtail or cease certain operations, and affect investor sentiment, our access to capital markets, our competitiveness and financial performance.

Policy, legal, regulatory, technological and market developments related to climate change could also affect future price assumptions used in the assessment of recoverability of asset-carrying values. This may affect whether there is continued intent to develop exploration and appraisal intangible assets; the timing of decommissioning of assets; and the useful economic lives of assets used for the calculation of depreciation and amortization.

Climate-related financial disclosures, **page 42** and Financial statements – **Note 1** and **Note 33**

Competition: inability to remain efficient, maintain a high-quality portfolio of assets and innovate could negatively impact delivery of our strategy in a highly competitive market.

Our strategic progress and performance could be impeded if we are unable to control our development and operating costs and margins, if we fail to scale our businesses at pace, or to sustain, develop and operate a high-quality portfolio of assets efficiently. Furthermore, as an integrated energy company, we face an expanded and rapidly evolving range of competitors in the sectors in which we operate.

We could be adversely affected if competitors offer superior terms for access rights or licences, or if our innovation in areas such as new low carbon technologies, digital, customer offer, exploration, production, refining, manufacturing or renewable energy lags behind those of our competitors. Our performance could also be negatively impacted if we fail to protect our intellectual property.

Talent and capability: inability to attract, develop and retain people with necessary skills, capabilities and behaviours could negatively impact delivery of our strategy.

The sectors in which we operate face increasing challenges to attract and retain diverse, skilled and capable talent. An inability to successfully recruit, develop and retain core skills and capabilities and to reskill existing talent could impact delivery of our strategy.

Crisis management and business continuity: failure to address an incident effectively could potentially disrupt our business.

Our reputation and business activities could be negatively impacted if we do not respond, or are perceived not to respond, in an appropriate manner to any major crisis.

Insurance: our insurance strategy could expose the group to material uninsured losses.

bp insures in situations where this is legally and contractually required. Some risks are insured with third parties and reinsured by group insurance companies. Uninsured losses could have a material adverse effect on our financial position, particularly if they arise at a time when we are facing material costs as a result of a significant operational event which could put pressure on our liquidity and cash flows.

Safety and operational risks

Process safety, personal safety, and environmental risks: exposure to a wide range of health, safety and environmental risks could cause harm to people, the environment and our assets and result in regulatory action, legal liability, business interruption, increased costs, damage to our reputation and potentially denial of our licence to operate.

Technical integrity failure, natural disasters, extreme weather or a change in its frequency or severity, human error and other adverse events or conditions, including breach of digital security, could lead to loss of containment of hazardous materials, including hydrocarbons★. This could also lead to fires, explosions or other personal and process safety incidents when drilling wells, constructing and operating facilities; in addition to activities associated with transportation by road, sea or pipeline. There can be no certainty that our OMS or other policies and procedures will adequately identify all process safety, personal safety and environmental risks or that all our operating activities, including acquired businesses, will be conducted in conformance with these systems.

Safety, **page 56**

Such events or conditions or inability to provide safe environments for our workforce and the public while at our facilities, premises or during transportation, could lead to injuries, loss of life or environmental damage. As a result, we could face regulatory action and legal liability, including penalties and remediation obligations, increased costs and potentially denial of our licence to operate. Our activities are sometimes conducted in hazardous, remote or environmentally sensitive locations, where the consequences of such events or conditions could be greater than in other locations.

Drilling and production: challenging operational environments and other uncertainties could impact drilling and production activities.

Our activities require high levels of investment and are sometimes conducted in challenging environments such as those prone to natural disasters and extreme weather, which heightens the risks of technical integrity failure. The physical characteristics of an oil or natural gas field, and cost of drilling, completing or operating wells are often uncertain. We may be required to curtail, delay or cancel drilling operations or stop production because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions and compliance with governmental requirements.

Security: hostile acts against our employees and activities could cause harm to people and disrupt our operations.

Acts of terrorism, piracy, sabotage, activism and similar activities directed against our operations and facilities, pipelines, transportation or digital infrastructure could cause harm to people and severely disrupt operations. Our activities could also be severely affected by conflict, civil strife or political unrest.

Product quality: supplying customers with off-specification products could damage our reputation, lead to regulatory action and legal liability, and impact our financial performance.

Failure to meet product quality specifications could cause harm to people and the environment, damage our reputation, result in regulatory action and legal liability, and impact financial performance.

Compliance and control risks

Ethical misconduct and non-compliance: ethical misconduct or breaches of applicable laws by our businesses or our employees could be damaging to our reputation, and could result in litigation, regulatory action and penalties.

Incidents of ethical misconduct or non-compliance with applicable laws and regulations, including anti-bribery and corruption, competition and antitrust, data privacy, and anti-fraud laws, trade restrictions or other sanctions, could damage our reputation, and result in litigation, regulatory action, penalties and potentially affect our licence to operate. In relation to trade restrictions or other sanctions, current geopolitical factors have increased these risks.

Regulation: changes in the law and regulation could increase costs, constrain our operations and affect our strategy, business plans and financial performance.

Our businesses and operations are subject to the laws and regulations applicable in each country, state or other regional or local area in which they occur. These laws and regulations result in an often complex, uncertain and changing legal and regulatory environment for our global businesses and operations. Changes in laws or regulations, including how they are interpreted and enforced, can and do impact all aspects of our business.

Royalties and taxes, particularly those applied to our hydrocarbon activities, tend to be high compared with those imposed on similar commercial activities. In certain jurisdictions there is also a degree of uncertainty relating to tax law interpretation and changes.

Governments may change their fiscal and regulatory frameworks in response to public pressure on finances or for other policy reasons, resulting in increased amounts payable to them or their agencies.

Changes in law or regulation could increase the compliance and litigation risk and costs, reduce our profitability, reduce demand for or constrain our ability to sell certain products, limit our access to new opportunities, require us to divest or write down certain assets or curtail or cease certain operations, or affect the adequacy of our provisions for pensions, tax, decommissioning, environmental and legal liabilities. Changes in laws or regulations could result in the nationalization, expropriation, cancellation, non-renewal or renegotiation of our interests, assets and related rights. Potential changes to pension or financial market regulation could also impact funding requirements of the group. Following the Gulf of America oil spill, we may be subjected to a higher level of fines or penalties imposed in relation to any alleged breaches of laws or regulations, which could result in increased costs.

Regulation of the group's business, **pages 329-334**

Trading and treasury trading activities: ineffective oversight of trading and treasury trading activities could lead to business disruption, financial loss, regulatory intervention or damage to our reputation and affect our permissions to trade.

We are subject to operational risk around our trading and treasury trading activities in financial and commodity markets, some of which are regulated. Failure to process, manage and monitor a large number of complex transactions across many markets and currencies while complying with all regulatory requirements could hinder profitable trading opportunities. There is a risk that a single trader or a group of traders could act outside of our delegations and controls, leading to regulatory intervention and resulting in financial loss, fines and potentially damaging our reputation, and could affect our permissions to trade.

Financial statements – **Note 29**

Reporting: failure to accurately report our data could lead to regulatory action, legal liability and reputational damage.

External reporting of financial and non-financial data, including reserves estimates, relies on the integrity of the control environment, our systems and people operating them. Failure to report data accurately and in compliance with applicable standards could result in regulatory action, legal liability and damage to our reputation.

★ See glossary on **page 351**

Compliance information

bp non-financial and sustainability information statement

Produced in compliance with Sections 414CA and 414CB of the Companies Act. Information incorporated by cross reference.

Requirement	Relevant policies and standards	Information related to policies and any due diligence processes
a Environmental matters	• Net zero aims • TCFD • Sustainability frame • Biodiversity position (online)	• Climate-related financial disclosures – **pages 42-55** • People and planet – **page 60** • Our Operating Management System★ (OMS) – **page 56** • Decision making by the board – **page 79**
b Employees	• bp values and code of conduct (online)	• Our people – **page 57** • Safety – **page 56** • Our values (Who we are) and code of conduct – **pages 58-59** • Employee engagement (Pulse annual and Pulse live employee surveys) – **page 58** • How the board engaged with stakeholders (workforce) – **page 78**
c Social matters	• Sustainability frame	• Our Operating Management System★ (OMS) – **page 56** • Improving people's lives – **page 60** • Decision making by the board – **page 79**
d Respect for human rights	• Business and human rights policy (online) • Modern slavery statement (online) • Labour rights and modern slavery principles (online) • Code of conduct (online)	• Improving people's lives – **page 60** • Human rights – **page 60** • Our values (Who we are) and code of conduct – **pages 58-59**
e Anti-corruption and anti-bribery	• Anti-bribery and corruption policy • Code of conduct (online)	• Ethics and compliance – **page 59** • Our partners in joint arrangements – **page 57**
Description of principal risks relating to matters (a-e above)		• How we manage risk – **pages 61-64** • Risk factors – **pages 65-67** • TCFD (climate-related risk management) – **pages 45-46**
	Relevant information	
Business model description	• Business model – **page 12**	
Description of non-financial KPIs	• Measuring our progress – **page 14 and pages 16-17**	

TCFD index table[a]

Our TCFD disclosures can be found on the following pages.

TCFD Recommendation	TCFD Recommended Disclosure	Where reported
Governance Disclose the organization's governance around climate-related issues and opportunities.	a Describe the board's oversight of climate-related risks and opportunities.	• **Page 45**
	b Describe management's role in assessing and managing climate-related risks and opportunities.	• **Page 46**
Strategy Disclose the actual and potential impacts of climate-related risks and opportunities on the organization's business, strategy and financial planning where such information is material.	a Describe the climate-related risks and opportunities the organization has identified over the short, medium, and long term.	• Pursuing a strategy that is consistent with the Paris goals, **page 10** • Strategy, **page 8** • Risk factors, **page 65**
	b Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy, and financial planning.	• Risk factors, **page 65** – description of principal risks • Strategy, **page 8**
	c Describe the resilience of the organization's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario.	• Strategy, **page 8** • Pursuing a strategy that is consistent with the Paris goals, **page 10**
Risk management Disclose how the organization identifies, assesses and manages climate-related risks.	a Describe the organization's processes for identifying and assessing climate-related risks.	• Risk Management, **page 45** • How we manage risk, **page 61** • Risk factors, **page 65**
	b Describe the organization's processes for managing climate-related risks.	• Risk Management, **page 45** • How we manage risk, **page 61**
	c Describe how processes for identifying, assessing, and managing climate-related risks are integrated into the organization's overall risk management.	• Risk Management, **page 45** • How we manage risk, **page 61** • Risk factors, **page 65**
Metrics and targets Disclose the metrics and targets used to assess and manage relevant climate-related risks and opportunities where such information is material.	a Disclose the metrics used by the organization to assess climate-related risks and opportunities in line with its strategy and risk management process.	• TCFD metrics and targets, **page 55**
	b Disclose Scope 1, Scope 2, and, if appropriate, Scope 3 GHG emissions, and the related risks.	• GHG emissions data, **page 40**
	c Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets.	• Our net zero aims and targets, **pages 38-39**

a We consider the information in our TCFD disclosures, taken together with our climate-related non-financial KPIs on **pages 14-17** of this report, to be compliant with the disclosure requirements of Section 414CB of the Companies Act, as amended by the UK CFD Regulations.

Section 172 statement

In accordance with the requirements of Section 172 of the Companies Act 2006 (the Act), the directors consider that, during the financial year ended 31 December 2024, they have acted in a way that they consider, in good faith, would most likely promote the success of the company for the benefit of its members as a whole, having regard to the likely consequences of any decision in the long term and the broader interests of other stakeholders, as required by the Act.

For more information in support of this statement, see board activities, **page 76**, our stakeholders, **page 78** and key decisions, **page 79**.

The Strategic report was approved by the board and signed on its behalf by Ben J.S. Mathews, company secretary, on 6 March 2025.

Corporate governance

Thunderhorse, US Gulf of America

★ See glossary on **page 351**

Introduction from the chair

"Our governance framework is designed to be dynamic, flexible and robust."

Dear fellow shareholders,

The role of a board as custodian of the company's assets has even greater significance in times of volatility, uncertainty and change. The unpredictable macro environment in 2024 offered both opportunities and challenges for global energy companies. Many of bp's businesses performed well but there were also challenges in parts of the customers & products business. Overall, it was a year of reshaping the portfolio and laying the foundations for bp's strategy reset in February 2025. The strategy we have set out provides clarity about direction and priorities, and the board will now focus its attention overseeing strategic execution and performance management.

Evolving governance framework

The board's corporate governance framework is a robust basis to challenge and guide the leadership team in good times, but also in the tougher times we have experienced. It has been instrumental in helping the board to navigate multiple, rigorous discussions and – ultimately – the decisions we took in 2024, culminating, more recently, in February's strategy reset.

Our governance framework is designed to be dynamic, flexible and robust. This meant that when the new UK Corporate Governance Code was published at the start of 2024, we could largely deploy our existing processes to plan for meeting its requirements, adding elements where appropriate while avoiding duplication and minimizing extra work.

The terms of reference for the board and the board committees were updated in July, with further changes to the board and audit committee terms of reference in January 2025, reflecting the staggered timetable of the changes coming into force under the new code. Considering the new requirement for an internal control effectiveness statement, we intend to make this statement in 2027 in respect of our 2026 annual report, having sought appropriate external assurance.

Meaningful engagement

Every year, we seek to engage widely with you, our shareholders, but also with our own people, partners, advisers and governments.

A highlight of 2024 was the board's trip to India. This was an invaluable experience for the board in a strategically significant region for bp. We travelled to three cities, meeting partners, suppliers and the government – and bp's teams working on lubricants, developing technical solutions and helping to run our operations safely (see **page 78**).

The board also met many other teams across the world, through our bespoke workforce engagement programme. This is designed to allow our directors to meet our people directly, throughout bp (see **page 78**).

Our 2024 workforce engagement agenda was aligned closely with the topics we discussed in reviewing and considering our strategic options at board meetings during the year. The views and feedback obtained played an important part in informing the board's decisions. This programme of listening to and working with our people will continue through 2025 – especially during an ongoing transformation programme.

Progress on culture

The board places great importance in assessing and monitoring bp's culture. Whenever necessary, it seeks the leadership team's assurance that action will be taken should practices or behaviours not align with the company's culture frame, which sets out 'Who we are'. The board set up a temporary committee in 2023 to provide direct oversight on culture. It served bp well and its responsibilities have now been assumed by the people, culture and governance committee.

As chair of this committee, I am pleased with the start we have made in 2024 with the committee's expanded scope on culture and, in particular, with a focus on psychological safety and speaking up. We will seek to make further progress on this area during 2025 (for more on the people, culture and governance committee's work, see **page 86**).

Board composition

The people, culture and governance committee is continuously working to identify potential candidates to join the board. The reset strategy bp announced in February 2025 provides the committee with a clear framework to identify new board members who will bring the additional skills and experience bp needs as it embarks on the next chapter.

Closing thanks

I am grateful to my fellow board members for everything they have done this year – and everything they continue to do. On behalf of the board, I would also like to thank the leadership team and bp teams across the world for what they achieved in 2024, for their relentless focus on safety and their commitment to bp. And I will close by thanking you, fellow shareholders, for your support and your challenges. Your contributions improve the board's decision making – and help to improve bp.

Helge Lund
Chair
6 March 2025

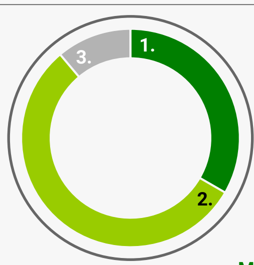
Board at a glance

	Board meeting attendance: 8 scheduled	Board meeting attendance: 2 ad hoc	Committee membership: Audit	Committee membership: Remuneration	Committee membership: People, culture and governance	Committee membership: Safety and sustainability	Skills and experience: Society, politics and geopolitics	Skills and experience: Technology, digital and innovation	Skills and experience: People leadership and organizational transformation	Skills and experience: Operational excellence and risk management	Skills and experience: Global business leadership and governance	Skills and experience: Finance, risk and trading	Skills and experience: Energy markets	Skills and experience: Climate change and sustainability
Non-executive directors[a]														
Helge Lund (Chair)	8/8	2/2			Chair		●		●	●	●		●	●
Dame Amanda Blanc	8/8	2/2		Member	Member		●		●	●	●	●		●
Tushar Morzaria	8/8	2/2	Chair	Chair					●	●	●	●		
Melody Meyer[b]	8/8	1/2		Member		Chair				●	●		●	●
Pamela Daley	8/8	2/2	Member	Member							●	●	●	
Hina Nagarajan	8/8	2/2	Member		Member			●	●	●	●			●
Satish Pai[c]	7/8	2/2				Member		●	●	●	●		●	●
Karen Richardson[c]	7/8	2/2	Member					●	●	●	●	●		
Dr Johannes Teyssen	8/8	2/2			Member	Member	●		●	●	●		●	●

Executive directors		
Murray Auchincloss (CEO)	8/8	2/2
Kate Thomson (CFO)[d]	7/7	1/1

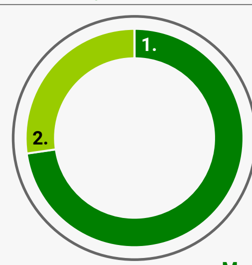
Chair of the committee
Member of the committee

Non-executive directors' tenure



	March 2025	March 2024
1. 1-3 years	3	6
2. 4-6 years	5	3
3. 7-9 years	1	2

Board ethnic diversity

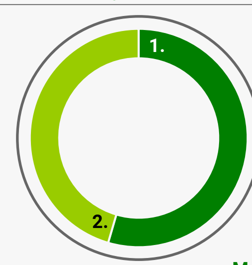


	March 2025	March 2024
1. White British or other white (including minority-white groups)	8	10
2. Asian/Asian British	3	3

3

directors who identify as from a minority ethnic background

Board gender diversity



	March 2025	March 2024
1. Female	6	7
2. Male	5	6

55%

of directors are female

a Paula Rosput Reynolds and Sir John Sawers stepped down from the board on 25 April 2024 and attended all meetings held prior to this date.
b Melody was unable to attend the ad hoc meeting in June due to an existing external commitment.
c Satish and Karen were unable to attend the scheduled meeting in June due to existing external commitments.
d Kate was appointed to the board on 2 February 2024 and attended all meetings held after this date.

★ See glossary on **page 351**

Board of directors

As at 6 March 2025

Helge Lund
Chair

P

Appointed Board: 26 July 2018; chair: 1 January 2019
Nationality Norwegian

External appointments

- Chair of Novo Nordisk AS.
- Operating advisor to Clayton Dubilier & Rice.
- Member of the Board of Trustees of the International Crisis Group.
- Member of the European Round Table for Industry.

Significant past appointments

- Chief executive of BG Group.
- President and chief executive officer of Equinor and Aker Kvaerner.
- Executive of Aker RGI and Hafslund Nycomed.
- Non-executive director of Schlumberger and Nokia.
- Consultant at McKinsey & Company.
- Parliamentary group political advisor of the Conservative party, Norway.

Key skills and experience

- Distinguished career as a leader in the energy sector with deep industry knowledge and global business experience.
- Drives cohesion, constructive challenge and oversight of bp's strategy through forward looking leadership of the board.

Murray Auchincloss
Chief executive officer

Appointed Executive director: 1 July 2020; chief executive officer: 17 January 2024
Nationality Canadian and British

Significant past appointments

- Joined Amoco in 1992 and then bp when the two companies merged in 1998.
- Senior roles in finance and management at bp, across tax, business development, mergers and acquisitions and performance management.
- Chief of staff to bp chief executive officer.
- CFO BP p.l.c.

Key skills and experience

- Drives bp's strategy as an integrated energy company and has extensive experience and knowledge of the energy sector.
- Provides deep insight into bp's assets and businesses through broad experience across the group, extensive financial expertise and experience.

Kate Thomson
Chief financial officer

Appointed 2 February 2024
Nationality British

External appointments

- Board member of Aker BP ASA.
- Member of the European Round Table for CFOs.
- Member of the 100 Group Main Committee.

Significant past appointments

- Joined bp in 2004.
- Group head of tax, BP p.l.c.
- Group treasurer, BP p.l.c.
- SVP finance for production & operations, BP p.l.c.

Key skills and experience

- Has a detailed understanding and experience of the energy sector and provides deep technical insight from her broad experience of leading teams across the group in tax, treasury and commercial finance.

Dame Amanda Blanc
Senior independent director

R P

Appointed 1 September 2022
Nationality British

External appointments

- CEO of Aviva plc.
- Member of the Association of British Insurers Board.

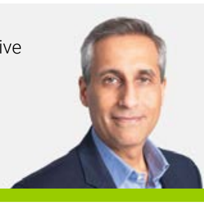
Significant past appointments

- Began career as a graduate at Commercial Union, one of Aviva's ancestor companies, and held several senior executive roles across the insurance industry.
- Group CEO at AXA UK, PPP & Ireland.
- CEO of Europe, Middle East, Africa & Global Banking at Zurich Insurance Group.
- Leadership positions at Groupama Insurance Company and Commercial Union.
- Member of the Prime Minister's Business Council.

Key skills and experience

- Experience leading insurance businesses in the UK and across Europe.
- Wide-ranging board, industry and regulatory experience.

Tushar Morzaria
Independent non-executive director



A R

Appointed 1 September 2020
Nationality British

External appointments

- Non-executive director of Legal & General Group plc.
- Non-executive director of BT Group plc.

Significant past appointments

- Various senior roles at JP Morgan, including CFO of its Corporate & Investment Bank.
- Group finance director and member of the board of Barclays PLC 2013 to 2022.
- Non-executive chairman of EMEA Investment Banking, Barclays until 2024.

Key skills and experience

- Over 25 years of strategic financial management, investment banking, operational and regulatory experience.
- Breadth of knowledge and insight into financial, tax, treasury, investor relations and strategic matters and strong experience in delivering corporate change programmes while maintaining a focus on performance.

Melody Meyer
Independent non-executive director

S R

Appointed 17 May 2017
Nationality American

External appointments

- Non-executive director of AbbVie Inc.
- Non-executive director of Airswift Parent LLC.

Significant past appointments

- President of Chevron Asia Pacific E&P until 2016 after 37 years of service in key leadership roles in global exploration and production.

Key skills and experience

- Deep understanding of the factors influencing safe, efficient and commercially high-performing projects in a global organization.
- Expertise in the execution of major capital projects, technology, R&D, creation of businesses in new countries, strategic business planning, merger integration, leading change, and safe and reliable operations.

Committee members key

Chair | A Audit committee | S Safety and sustainability committee | R Remuneration committee | P People, culture and governance committee

Pamela Daley
Independent non-executive director

A R

Appointed 26 July 2018

Nationality American

External appointments

- Director of BlackRock, Inc.

Significant past appointments

- Various senior executive roles at General Electric Company (GE), including senior vice president of business development 2004 to 2013.
- Senior vice president and senior advisor to the chair at GE in 2013.
- Director of BG Group plc 2014 to 2016.
- Director of Patheon N.V. 2016 to 2017.
- Partner at Morgan, Lewis & Bockius.
- Director of SecureWorks, Inc. 2016 to 2025.

Key skills and experience

- Board-level experience of the UK oil and gas industry and executive experience in highly regulated industries.
- Qualified lawyer with a wealth of global business and strategic experience.

Karen Richardson
Independent non-executive director

A

Appointed 1 January 2021

Nationality American

External appointments

- Partner at Artius Capital Partners.
- Non-executive director of Artius II Acquisition Inc.
- Non-executive director (lead independent director) of Exponent, Inc.

Significant past appointments

- Senior operating roles in the public and private technology sector.
- Vice president of sales at Netscape Communications Corporation 1995 to 1998.
- Senior executive roles at E.piphany from 1998, including CEO 2003 to 2006.
- Non-executive director of BT plc 2011 to 2018.
- Director of Worldpay Inc. (Worldpay Group plc) 2016 to 2019.
- Chair of Origin Materials Inc. 2021 to 2024.

Key skills and experience

- Extensive knowledge of digital, technology, cyber and IT security matters.
- 30 years' technology industry experience including working with innovative Silicon Valley companies.

Satish Pai
Independent non-executive director

S

Appointed 1 March 2023

Nationality Indian

External appointments

- Managing director of Hindalco Industries Limited.
- Director of Novelis Inc.
- Non-executive director, Aditya Birla Management Corporation Ltd.
- Director, Indian Institute of Metals.

Significant past appointments

- Executive vice president, worldwide operations and other engineering and management roles at Schlumberger across 28 years of service.

Key skills and experience

- Accomplished and transformative executive with operations and technology experience in the resources and energy industries.
- Strong digital capability and experience.

Hina Nagarajan
Independent non-executive director

A P

Appointed 1 March 2023

Nationality Indian

External appointments

- Managing director and CEO of United Spirits Limited (Diageo India).
- Member of the global executive committee of Diageo plc.
- Board member of The Advertising Standards Council of India.
- Director and co-chair of International Spirits and Wines Association of India.

Significant past appointments

- Leadership positions at Reckitt, Mary Kay India and Nestlé India with over 30 years in the fast-moving consumer goods (FMCG) industry.
- Non-executive director at two companies which were publicly quoted at the time: Guinness Ghana Breweries Plc and Seychelles Breweries Limited.

Key skills and experience

- Deep and wide-ranging experience in customer-focused FMCG businesses in complex emerging markets.
- Extensive experience in assessing climate-related risks and opportunities.

Dr Johannes Teyssen
Independent non-executive director

S P

Appointed 1 January 2021

Nationality German

External appointments

- Senior advisor to Kohlberg Kravis Roberts.
- President of Alpiq Holding Ltd.
- Senior advisor to Viridor Limited.

Significant past appointments

- Several leadership positions at VEBA AG (merged with VIAG AG in 2000 and renamed to E.ON AG and later to E.ON SE).
- Member of the board of management of the E.ON Group's central management company in Munich in 2001 and E.ON SE in 2004.
- Vice-chair of E.ON SE, 2008 and CEO, 2010 to 2021.
- President of Eurelectric 2013 to 2015.
- Vice-chair of the World Energy Council, responsible for Europe, 2006 to 2012.
- Member of the supervisory board of Salzgitter AG 2006 to 2016 and Deutsche Bank AG 2008 to 2018.

Key skills and experience

- Extensive experience and deep knowledge of the energy sector and its continuing transformation.
- Considerable knowledge and experience of climate-related risk oversight.

Ben J S Mathews
Company secretary

Appointed 7 May 2019

Role and career summary

Ben joined bp as company secretary in May 2019. He is the co-chair of the Corporate Governance Council of the Conference Board and is a Fellow of the Chartered Governance Institute. Ben serves on the executive committee of the Association of General Counsel and Company Secretaries of the FTSE 100 (GC100), having previously served as its chair for four years.

Ben's global company secretary team is responsible for providing advice and support to the plc board and the boards of other legal entities in the bp group. The team's vision is to enhance stakeholder value through dynamic corporate governance.

Former appointments include Group Company Secretary of HSBC Holdings plc and Rio Tinto plc.

For further detail on the directors' climate change and sustainability experience, see the TCFD section on page 43 and further biographical information for each director is available online at bp.com/whoweare.

★ See glossary on **page 351**

Leadership team

William Lin
EVP gas & low carbon energy

Leadership team tenure Appointed on 1 July 2020

Nationality American

Board memberships

William is a non-executive director of Pan American Energy Group, the largest independent energy company in Argentina. He is also a member of the supervisory board for Corbion, a Dutch-listed global food ingredients and biochemicals company. He chairs Corbion's Sustainability & Safety Committee and is a member of the Audit Committee.

Career summary

William has worked at bp for 29 years and now leads the group's global natural gas and low carbon businesses and markets. Prior to this role, he held other senior management positions including the chief operating officer for upstream regions, regional president for Asia Pacific, and vice president for gas developments and operations for Egypt.

Emma Delaney
EVP customers & products

Leadership team tenure Appointed on 1 July 2020

Emma previously served on bp's executive team starting on 1 April 2020

Nationality Irish

Board memberships

None

Career summary

Emma has spent 28 years working in bp, both in the upstream and the downstream. Prior to joining bp's executive team on 1 April 2020, she was regional president for West Africa. She has held a variety of senior roles including upstream chief financial officer for Asia Pacific and head of business development for gas value chains. In downstream she held roles in retail and commercial fuels and planning.

Giulia Chierchia
EVP strategy, sustainability & ventures

Leadership team tenure Appointed on 1 July 2020

Nationality Belgian and Italian

Board memberships

Giulia is a non-executive director of Schneider Electric.

Career summary

Giulia joined bp in April 2020 as EVP strategy, sustainability & ventures. In her role, Giulia drives bp's strategy and sustainability agenda and embeds the group's ethics and compliance within the organization. She oversees bp's venturing investments business, which supports bp's transition and net zero ambition. Prior to bp, she worked for McKinsey, where she was a senior partner. She led the global downstream oil and gas practice and was a key member of the chemicals, and electricity, power and natural gas practices, helping companies shape their strategies for the energy transition.

Gordon Birrell
EVP production & operations

Leadership team tenure Appointed on 1 July 2020

Gordon previously served on bp's executive team starting on 12 February 2020.

Nationality British

Board memberships

Gordon is a non-executive director of Azule Energy Holdings Ltd.

Career summary

Before being appointed to his new role, Gordon was chief operating officer for production, transformation and carbon. In his bp career, Gordon has spent time in various leadership, technical, safety and operational risk roles, including four years as bp president Azerbaijan, Georgia and Türkiye. Gordon is a Fellow of the Royal Academy of Engineering.

Emeka Emembolu
EVP technology

Leadership team tenure Appointed on 18 April 2024

Nationality British

Board memberships

None

Career summary

Emeka started his career working offshore as an engineer and has spent 25 years with bp. Prior to being appointed EVP technology, Emeka spent two years as chief of staff to the CEO. Before joining the executive office, he led bp's North Sea business as region SVP spearheading improvements in operational safety, driving efficiencies and growing the value of the business. Prior to that, he held a range of senior technical leadership roles in the Gulf of America, Canada, North Africa and Alaska and in the subsurface function.

Carol Howle
EVP supply, trading & shipping

Leadership team tenure Appointed on 1 July 2020

Nationality British

Board memberships

None

Career summary

Before taking on her current role, Carol ran bp shipping and was the chief operating officer for integrated supply and trading, oil. She has more than 20 years' experience in the energy industry, and many in integrated supply and trading. Her previous roles include chief operating officer for natural gas liquids, regional leader of global oil Europe and finance. Carol also served as the head of the group chief executive's office.

Kerry Dryburgh
EVP people, culture & communications

Leadership team tenure Appointed on 1 July 2020

Nationality British

Board memberships

None

Career summary

Kerry leads people, culture & communications at bp. Kerry previously headed HR for bp's upstream business while also serving as group chief talent officer. She has held a series of senior HR positions across the company, including running HR for bp's shipping, integrated supply and trading, and corporate functions. She brings vast experience from other sectors in Europe and Asia, having worked at both BT and Honeywell.

Mike Sosso
EVP legal

Leadership team tenure Appointed on 1 January 2024

Nationality American

Board memberships

None

Career summary

Mike took on the role of EVP legal in January 2024. In his role, Mike is accountable for leading the legal function and executing the legal strategy for the group. Mike joined bp in 2011 and has held a number of leadership positions across legal. He also previously held the role of VP ethics and compliance. Prior to joining bp, Mike practised law in the Washington, DC office of Skadden, Arps, Slate, Meagher & Flom.

Governance framework

Board of directors

Non-executive directors
- Chair
- Senior independent director
- Independent non-executive directors

Executive directors
- Chief executive officer
- Chief financial officer

Company secretary

Board committees

- Safety and sustainability committee — Report from **page 80**
- Audit committee — Report from **page 82**
- People, culture and governance committee — Report from **page 86**
- Remuneration committee — Report from **page 88**

Executive leadership

bp leadership team

bp's governance framework helps to drive informed and efficient decision making through a clear division of responsibilities. This enables bp to operate effectively and in alignment with the strategy as set by the board.

Responsibilities of the board

The board is appointed by shareholders. Its responsibility, through the directors, is to promote the success of the company, to drive value for shareholders, having regard for the company's stakeholders and the consequences of decisions in the long term. Fulfilling this role, the board is responsible for setting and overseeing the implementation of the company's strategy, purpose and values. The board's oversight includes monitoring culture and the effectiveness of the company's system of internal control.

More detailed information about board activities is available from **page 76**.

Delegation of authority

The board delegates certain responsibilities to its principal committees, which are outlined in their respective terms of reference at **bp.com/governance**.

Day-to-day management of the business is delegated to the chief executive officer (CEO), who in turn is advised and supported by a leadership team (bpLT) comprising of nine individuals who are accountable to him for their respective business and functional areas, with appropriate financial authority levels. Ultimately, decisions are taken by the CEO in the execution of the delegations to him by the board.

For example, the CEO's authority includes a limit on investments, capital expenditure★ and financial commitments. Any matters in excess of this limit, or those that go beyond the annual plan or agreed strategy, remain a matter reserved for the board as a whole.

Further delegations of authority are maintained throughout the business in a consistent way.

Board committees

The four principal board committees operate under terms of reference which are reviewed at least annually. Full details can be found at **bp.com/governance**.

Each committee reports to the board as a whole, providing updates on their activities and, where applicable, making recommendations for the board's approval.

Board roles

Non-executive directors (NEDs)

Provide independent oversight, mentoring and constructive challenge to the executive directors and bpLT. NEDs bring valuable external perspective and support good governance in matters such as remuneration and succession planning.

Chair

- Helge Lund leads the board and is responsible for its overall effectiveness.
- This includes shaping and managing the culture of the boardroom, facilitating the board's ability to hear the views of stakeholders, and overseeing the composition and development of the board.

Senior independent director (SID)

- Dame Amanda Blanc acts as a sounding board for the chair and, if necessary, as an intermediary for other directors and investors.
- This includes overseeing the performance evaluation and succession planning for the chair.

Executive directors

Executive directors are tasked with the implementation of bp's strategy and are responsible for all executive management matters affecting the company.

Chief executive officer (CEO)

- As CEO, Murray Auchincloss proposes bp's strategy and annual plan for endorsement by the board, and leads the bpLT in delivering them.
- This involves overseeing the implementation of the system of internal controls and responsibility for setting policies, standards and procedures that foster bp's culture and values.

Chief financial officer (CFO)

- Kate Thomson provides financial leadership for the business and supports the CEO in the development and implementation of the strategy.

Company secretary

Ben Mathews advises the board on corporate governance matters, change to and compliance with board procedures, and monitors regulatory requirements. He also supports the chair in ensuring the timely flow of accurate and clear information to the board.

★ See glossary on **page 351**

Board activities: promoting long-term sustainable success

In 2024 the board and its committees held regular meetings as needed to address business requirements. Agendas were set in advance by the chair, CEO, and company secretary, focusing on four pillars of strategy, performance, people, and governance.

The board's activities, supported by its committees, spanned these pillars. Notably, overseas trips to both Houston, US, and across India allowed the board to engage directly with a range of stakeholders. Highlights of the board's activities, discussions and approvals during the year are provided below.

Strategy

Strategic direction TCFD

- Worked closely with the CEO and his leadership team to establish a new purpose and strategy reset for bp.
- Discussed strategic progress and options at every board meeting, including deep-dives into our transition businesses★.

Macroeconomics TCFD

- The review of our strategic direction was informed by regular updates on macroeconomic and geopolitical factors affecting our strategy, plan and performance.

Mergers and acquisitions pipeline

- Regular reviews of potential merger, acquisition and divestment opportunities, including transition and low carbon. TCFD
- Approved the acquisition of transition business, bp Bunge Bioenergia (see **page 33**). TCFD
- Approved the final investment decision for Kaskida which will be bp's sixth hub in the Gulf of America.

Offsites

- The board's site visits this year included:
  - Permian Basin, Gulf of America.
  - bp Houston in the US.
  - The Castellón refinery in Spain.
  - *Castrol* Patalganga plant and bp's business and technology centers in Pune, in India.
  - Our Reliance-operated KG D6 gas facility in India.

Technology

- Received an update on digital, including its functional reorganization, the development of new strategic partnerships (Palantir, Infosys) and priorities for 2025.
- Participated in a deep-dive session on the potential deployment of generative artificial intelligence solutions across bp businesses.

Safety and sustainability TCFD

- Reviewed ongoing updates on safety measures and performance.
- Focused its sustainability aims on those most relevant to the long-term success of its businesses and to its net zero ambition

Performance

Annual plan

- Reviewed and approved the 2024 annual plan that considered capital allocation (including transition businesses) to improve the balance sheet. TCFD
- Reviewed full-year delivery against the 2023 plan, and monitored progress against 2024 objectives.

Financial frame and distributions

- Evaluated potential enhancements and simplifications to the financial frame.
- Regularly reviewed shareholder distribution options in alignment with the financial frame.

Capital expenditure

- Received an update from the CEO at every board meeting covering projects across all bp's businesses and, where appropriate, climate-related considerations. TCFD These updates included any inorganic or divestment opportunities of more than $100 million.

Acquisition reviews

- Evaluated progress on the integration of transition businesses, Archaea Energy and TravelCenters of America. TCFD

Principal risks

- Analysed trends and themes arising from risk management reports.
- Performed mid-year and full-year reviews of bp's principal and emerging risks, including those related to climate (see **page 112**). TCFD

Internal controls

- Evaluated the group's internal control and risk management systems as part of the review and approval of the bp Annual Report and Form 20-F.
- Received reports from group risk and internal audit, no specific concerns were identified, and the board concluded that the systems remain resilient, fit for purpose, and aligned with external expectations (see how we manage risk on **page 61** and bp's system of internal control on **page 112**).

Key

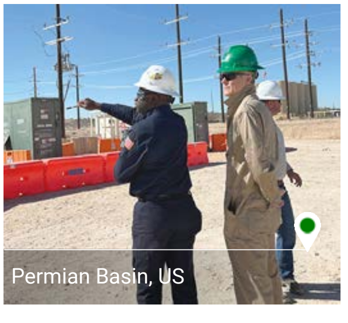
TCFD	TCFD Recommendations and Recommended Disclosure

Highlights of the year

January – March

February:
- Site visit to bpx energy and Archaea, US.
- People, culture and governance; remuneration; audit; and safety and sustainability committee meetings, including Q4 results, London.
- Board meeting, London.

March:
- People, culture and governance; remuneration; and audit committee meetings, virtual.
- Board meeting, virtual.


Permian Basin, US

April – June

April:
- People, culture and governance committee meeting, virtual
- Remuneration committee meeting, virtual
- Annual General Meeting, London

May:
- Audit committee and board meetings, including Q1 results, virtual.

June:
- Houston, US, board programme including a safety and sustainability committee site visit to the Permian Basin and Gulf of America and a trading and shipping floor walk with the audit committee.
- Ad-hoc board meeting, virtual.


Argos platform, US Gulf of America

People

Engagement
- Participated in the workforce engagement programme (WFEP), bringing employee feedback into the boardroom and therefore allowing board decisions to be better informed of stakeholder views (see **page 78**).
- Met with high-potential employees to help improve the board's visibility of the executive succession pipeline.
- Held town halls and undertook site visits to increase director interaction with the workforce in those locations (further information on in-person site visits on **page 78**).

Culture
- Received feedback from Pulse employee surveys, agreeing actions and initiatives in response.
- Reviewed the annual ethics and compliance report, and the function’s priorities and objectives.
- Approved the scope of the newly named people, culture and governance committee.

Conflicts of interest
- Approved an amended conflicts of interest policy that integrated mandatory disclosure and reporting requirements for relationships at work.

Succession planning
- Supported by the people, culture and governance committee, the board received updates on succession plans for the board, and undertook a review of leadership development initiatives, including succession plans for the bp leadership team.

Governance

Corporate governance framework
- Approved changes to the terms of reference for the board and committees to align with regulatory changes under the revised UK Corporate Governance Code and to reflect evolving governance practices at bp.

Board composition / director changes
- Following a comprehensive selection process, appointed Murray Auchincloss as the permanent chief executive officer with effect from 17 January 2024, and Kate Thomson as chief financial officer and board member on 2 February 2024.
- Appointed Dame Amanda Blanc as senior independent director (SID) with effect from 25 April 2024.
- Appointed Tushar Morzaria as interim remuneration committee chair with effect from 25 April 2024.
- Appointed Hina Nagarajan and Johannes Teyssen as additional members of the people, culture and governance committee with effect from 6 May 2024.

Director training and knowledge sessions
- Completed online training on topics including the code of conduct and cyber security.
- Participated in a number of deep-dive sessions during the year on relevant topics such as artificial intelligence.

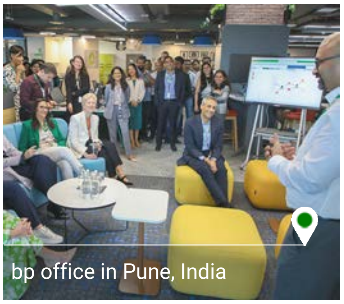
Board effectiveness review
- Conducted an externally facilitated board and committee performance review led by the chair and company secretary (see **page 87**).

Investor engagement
- The chair, senior independent director, remuneration committee chair, SVP investor relations and company secretary held a number of investor meetings with shareholders representing around 30% of the share capital.

July – September

July:
- People, culture and governance; remuneration, audit; and safety and sustainability committee meetings, including Q2 results, London.
- Board meeting, London.
- Safety and sustainability committee site visit to Castellón refinery, Spain.

September:
- India board programme, including safety and sustainability committee site visit to *Castrol* Patalganga and audit committee site visit to Pune.



bp office in Pune, India

October – December

October:
- Audit committee; board; and results committee meetings, including Q3 results.

November:
- People, culture and governance; remuneration; audit and safety and sustainability committee meetings, London.
- Board meeting, London.

December:
- Audit committee meeting, virtual

Castrol, Pangbourne, UK

Our stakeholders

Regular stakeholder engagement allows directors to gain a wide range of different insights, giving the board a comprehensive and rounded perspective in support of the decisions it takes. Engagement of this nature helps the directors to fulfil their statutory duties and build greater trust within, across, and outside of bp. In turn this helps improve how the strategy is formed and overseen to promote bp's long-term success.

Fostering mutual understanding

The board's approach to stakeholder engagement allows for a better understanding of matters that are important and relevant to the decisions that they take and to the continuing evolution of bp's strategy.

For the non-executive directors (NEDs), one of the key mechanisms for engagement is the workforce engagement programme (WFEP). Every NED takes part in the WFEP, joining small group roundtable sessions with employees on a specific topic. Key themes addressed through the WFEP in 2024 included safety, innovation and technology, remuneration, and culture.

In addition, for employees, directors have been involved in town hall events and webcasts during the year.

For investors, engagement mechanisms included roadshows, results calls, one-to-one and group meetings.

bp's financial and operational performance was an important topic for both investors and the workforce in 2024, with directors seeking to enhance each group's understanding of the factors affecting the company's overall performance.

Promoting balanced perspectives

In 2024, engagements included sessions with employees in Australia, India, Spain, the UK and US; summits and meetings with governments and regulators from Azerbaijan, Germany, Kuwait, India and Iraq; and customer-focused visits to sites in the UK, US and India.

In particular, the board's visit to our business and technology centers in Pune, India in September provided a breadth of stakeholder engagement opportunities, supporting the delivery of bp's ambitions. For more on the visit to Pune see **page 83.**

In addition to regular meetings with investors in 2024, bp held its first hybrid retail shareholder engagement event outside of the AGM, hosted by the company secretary. Feedback from this event was used to enhance engagement by the board at the AGM.

Focusing strategic direction

The strategy reset announced in February 2025 was developed through a comprehensive engagement programme undertaken in 2024 and early 2025. The perspectives of various stakeholders were considered including investors and our employees. Wide-ranging views helped to inform the decisions taken by the board regarding the strategy reset. This engagement supported the board's confidence that their decisions had taken account of evolving stakeholder expectations.

See more on key decisions, **page 79**

Building trust in bp

Two important themes in helping to maintain and enhance organizational trust are safety performance and culture.

On safety, valuable insights were gained from investors, employees and business partners via in-person meetings, online meetings and director site visits. Examples this year included visits to the Castellón refinery in Spain and operations in the Permian Basin in the US.

Culture was a prominent theme of WFEP sessions in 2024 with valuable feedback shared on culture at bp, including the impact of agile working and leadership training programmes.

In addition, directors continued to advocate for bp's culture of speaking up, and the board reviewed an anonymized summary of Pulse employee survey reports and OpenTalk reports (bp's whistleblowing service). For more on culture see **page 87.**

Opportunities for collaboration

By attending talks, events and site visits with our partners and suppliers (such as Reliance, Infosys and Aviation Fuelling Services at Heathrow airport (UK)), the board had the opportunity to discuss and learn more about safety, technology and the future of the energy sector.

Similarly, engagements with governments and regulators and consideration of wider society's interests focused on generating shared value. For example, investment opportunities (Kaskida platform, Gulf of America), redevelopment opportunities (Kirkuk Field, Iraq) and exploration of lower carbon energy solutions (Net Zero Teesside Power, UK).

The directors also reflected on integration, safety and customer-centricity on their visits to retail sites such as TravelCenters of America in the US and the Hemel Hempstead fuel terminal in the UK.

Benchmarking progress

Stakeholder engagement enhances the board's ability to benchmark our progress against peers and to innovate, ultimately benefiting our shareholders, workforce, customers, suppliers and business partners, and the communities where bp operates.

Our Section 172(1) statement describes how the directors have had regard to the matters set out in Section 172(1)(a) to (f) of the Companies Act 2006; see page 68.

Further information on the board's activities and key decisions, including how stakeholder interests have been considered, can be found on pages 76-78 and page 79.

bp office in Pune, India

Stakeholders key

- Investors and shareholders
- Customers
- Workforce
- Governments and regulators
- Partners and suppliers
- Society

Key decisions

Section 172 of the Companies Act 2006 requires directors to act in a way they believe will promote the success of the company for the benefit of its shareholders. They must consider the long-term impact of their decisions, the interests of employees, relationships with stakeholders, the community and environment, and maintain high standards of business conduct.

Set out below are four key decisions taken by the board during 2024 and how stakeholder considerations have been taken into account in the board's discussions and decision making.

Resetting our strategy

The board approved a reset of bp's strategy and reallocation of capital to drive growth and improved performance, as announced at the Capital Markets Update on 26 February 2025.

This announcement followed extended workshops and board discussions with members of the bp leadership team at each board meeting since September 2023, leading to what the board believes is a clear and distinctive strategic direction, an investable financial proposition, with a simpler narrative, sustainability framework, financial frame and metrics.

Throughout the process, the board explored what drives valuation growth across three quantitative pillars – growth, profitability, and risk – along with qualitative factors like investor proposition, market confidence, and the company's performance during the year.

bp's investors want to see consistent operational and financial performance, together with strategic clarity with less complexity. The board discussed choices on capital allocation and efficiency, balance sheet resilience and share buyback guidance.

When looking at the potential strategic options, the board also considered bp's sustainability framework.

Recognizing the feedback to become a simpler and more understandable organization, the board considered the perspectives of various stakeholders including investors and our employees before approving the five focused sustainability aims of net zero operations★, net zero sales★, people, water and biodiversity.

Throughout the process the board explored potential scenarios, opportunities, and risks. This ultimately led to decisions being taken that the board believes will best maximize bp's prospect of achieving its objectives and fulfilling its purpose. The board believes the strategy remains consistent with the goals of the Paris Agreement. Recognizing that the component parts of this update are important to many stakeholder groups, the board remains committed to the energy transition.

Stakeholders considered

An integrated energy company

As an integrated energy company, bp continues to invest with discipline in both the upstream★ and low carbon energy. In 2024, the board approved key investment decisions in each of these segments.

In July, bp took a final investment decision for a sixth operated hub, Kaskida, in the US Gulf of America. This strategic growth project represents bp's ongoing commitment to invest in this prolific high-margin basin, and makes up an important element of growing the value of bp. This platform is expected to have production capacity of 80,000 barrels of oil per day and will embrace a more simplified, standardized and cost-efficient platform design that we plan to replicate in future projects, unlocking potential for the development of 10 billion barrels of discovered resources in place in the Paleogene, Gulf of America.

Together with our partners we reached financial close for two major carbon capture and storage (CCS) projects in Teeside in the north-east of England: the Northern Endurance Partnership (NEP) and Net Zero Teesside Power (NZT Power). NEP, through its CO_2 transport and storage system, will help develop and underpin a lower carbon future for industry in the region. NZT Power, a gas-fired power station with CCS, will provide flexible low carbon power into the UK national power grid. The two projects will capture and transport millions of tonnes of CO_2 and the board noted the potential from these projects to support thousands of jobs through their construction and operation.

The NZT Power and NEP decisions were taken following extensive dialogue with multiple stakeholders, including discussions with governments regarding local policies and with our customers to ensure an accessible market. The board recognized the contribution of the NZT Power and NEP decisions to bp's strategic priorities, including the high grading of our hydrogen and CCS projects and the role these projects can play in helping advance the UK's journey to net zero.

In the US, the board was supportive of the high-value growth opportunity presented by Kaskida and the contribution it could make to deliver secure, reliable and affordable energy.

Stakeholders considered

★ See glossary on **page 351**

Safety and sustainability committee

Melody Meyer
Safety and sustainability committee chair

"The committee undertook a number of site visits to engage with employees and observe bp's safety and sustainability culture and performance in person."

Meetings and attendance

The committee met five times during 2024. Regular attendees included SVP internal audit, EVP production & operations, EVP strategy, sustainability & ventures, SVP HSE and carbon, SVP safety and operational risk assurance, SVP sustainability and VP internal audit – safety and sustainability.

Non-executive directors	Five scheduled meetings
Melody Meyer: member (from May 2017), chair of the committee (from November 2019)	5/5
Satish Pai: member[a]	4/5
Sir John Sawers: member (until April 2024)	1/1
Johannes Teyssen: member	5/5

a Satish Pai was unable to attend the scheduled meeting in June due to an existing external commitment.

Chair's introduction

Dear fellow shareholders,

I am pleased to present the safety and sustainability committee report for the year ended 31 December 2024.

Safety performance remained a focal point for the committee during the year, with the committee observing significant progress made in reducing tier 1 process safety incidents. This included overseeing management's progress in the implementation of Process Safety Improvement Plans (PSIPs) across the company, with deeper dives on personal safety, operational integrity and threat risk across a number of our businesses and operations.

Tragically, we lost a colleague in our recently acquired bp bioenergy business in Brazil from injuries sustained during an operational activity. We extend our deep condolences to his family and colleagues. Management reported on the actions being taken to embed the bp Operational Management System across bp bioenergy and to learn from this incident.

The committee undertook a number of site visits to engage with employees and observe bp's safety and sustainability culture and performance in person. The committee members appreciated the candour and culture experienced at each site visited, details on **page 81.**

Looking forward to 2025, the committee will focus its oversight on maintaining the good progress and continuous improvement in safety performance and implementation of the updated sustainability aims (further detail on **page 38**).

Role of the committee

The committee oversees the management of safety and sustainability matters, including relevant systems and processes, focusing on those which it considers to be most potentially material from time to time.

Key responsibilities

The committee's full terms of reference can be viewed at **bp.com/governance**.

Melody Meyer
Committee chair
6 March 2025

Activities during the year

Overseeing improved safety performance

- One primary focus of the committee is the oversight of safety performance, critically analysing management's progress in the reduction of tier 1 and 2 process safety events★. During 2024, the committee oversaw improved tier 1 safety performance, with tier 1 safety events being 67% lower than in 2023.
- Additionally, the committee oversaw the implementation of PSIPs to address a 17% increase in tier 2 safety events in the year. This included overseeing the continued embedding of the Refining, Terminals and Pipelines 5-Point Plan, created as a priority initiative following fatalities at the Toledo refinery in September 2022.
- In addition, the committee received:
  - Routine updates from the EVP production & operations on safety and operational performance and key safety moments from around the business.
  - Reports on major operational, security (including crisis management and business continuity) and cyber security incidents (for example, detail on learnings from the global CrowdStrike outage in July 2024).
  - Deep-dive updates regarding significant or material events and specific risk areas within the business, including a fatality at Guariroba mill in our recently acquired bp bioenergy business in Brazil from exposure to steam at extreme temperature, and a full shutdown at Whiting refinery in the US resulting from a power outage. The committee challenged management on the root cause and learnings from these incidents and how learnings are embedded into existing safety processes.
  - The committee also made recommendations to the remuneration committee regarding safety remuneration targets and outcomes. This included critically analysing current methodologies for the setting of targets to ensure they are appropriately achievable while remaining stretching.

Providing challenge on risk management

- The committee plays an important role in the bp risk management process, providing independent challenge to management on the processes and procedures implemented to manage safety and sustainability risk. This is achieved by reviewing and monitoring the principal risks allocated to it by the board through deep-dive updates, for example related to wells, product quality and ethical misconduct and non-compliance.
- Proactive deep-dives are made into specific areas of risk within the business. For example, the committee began receiving enhanced reporting on risk management within the bpx energy business, which continued into 2024. This reporting has allowed the committee to challenge the business on the cascading of safety learnings and implementation of process safety improvement plans, demonstrated by improved safety performance within bpx energy during 2024.
- Routine updates on the activity of internal audit are received by the committee, including an annual report on bp's system of internal control. This supports the committee by providing an independent view on management's safety and sustainability performance, helping to draw out where key challenges and risk areas may lie.

Guiding delivery against strategy and aims TCFD

- The committee oversees progress against bp's sustainability aims through receiving routine updates from the SVP sustainability. During 2024, deep-dives were undertaken into each pillar of the sustainability frame, with regular focus on management's plans to address areas of more challenged delivery.
- The committee remains abreast of the current global sustainability reporting environment, including bp's plans for compliance. For example, in November, the committee received a joint update with the audit committee on bp's plans for compliance with the EU Corporate Sustainability Reporting Directive and EU Taxonomy Regulation.
- Recommendations were made to the remuneration committee regarding sustainability-linked remuneration targets and outcomes. For example, the committee made a recommendation to the remuneration committee to move the 2024 annual cash bonus target from sustainable emissions reductions to one based on operational emissions reductions (see remuneration report on **page 88**).

Key

TCFD	Information that supports TCFD Recommendations and Recommended Disclosures in relation to governance (see **pages 42-45**)

Castellón refinery, Spain

Insights from Castellón refinery, Spain – July 2024

During the S&SC's trip to Castellón refinery the team provided an insight into its implementation of the 5-Point Plan and other PSIPs. The team also briefed the committee on the cascading of learnings following a fatality on-site in 2021, including consequent reinforcement of the Life Saving Rules on-site and piloting of a bespoke safety programme (Safety in Mind) to embed human performance principles of safety on-site. In addition, the committee was briefed on plans to develop the asset's green hydrogen★ operations.

> "The local team provided the S&SC with an insight into its implementation of the 5-Point Plan and other PSIPs."

Sustainability initiatives at *Castrol*, India – September 2024

The committee observed first-hand several of *Castrol*'s innovative sustainability initiatives, including ambient temperature blending, electricity optimization measures and its strategy to use 100% renewable energy from the local grid. The trip was also an opportunity to hear from the local team how it has improved safety performance through digitization, including automated maintenance management.

Castrol plant, India

★ See glossary on **page 351**

Audit committee

Tushar Morzaria
Audit committee chair

> "The committee oversaw significant change in bp's reporting processes in the year."

Meetings and attendance

The committee met nine times during 2024. Regular attendees included the chief financial officer (CFO), SVP accounting, reporting and control, SVP internal audit, EVP legal, and the external auditor.

Non-executive directors	Nine scheduled meetings
Tushar Morzaria: member (from September 2020), chair of the committee (from May 2021)	9/9
Pamela Daley: member	9/9
Paula Reynolds: member (until April 2024)	2/2
Karen Richardson: member	9/9
Hina Nagarajan: member[a]	8/9

a Hina was unable to attend the meeting in December due to an existing external commitment.

Chair's introduction

Dear fellow shareholders,

I am pleased to present the audit committee report for the year ended 31 December 2024.

At the heart of the committee's role is bp's financial reporting – monitoring its continued integrity, overseeing management's control procedures and assessing their effectiveness and working with internal and external auditors to ensure that what you – our shareholders – rely on in our reporting has been appropriately challenged and reviewed. This is work we undertake on behalf of the board, co-ordinating with some of the board's other committees for their relevant input and ultimately making recommendations to the board in support of the governance processes we have established.

In pursuit of this agenda, the committee oversaw significant change in bp's reporting processes in the year, with the introduction of trading statements which are now issued shortly after the end of the quarter to provide up-to-date performance insights.

A highlight of our activity during the year has included monitoring progress against bp's target relating to the delivery of savings[b], and the committee will continue to monitor progress in 2025 following the announcement on 26 February 2025 to deliver between $4-5 billion of structural cost reductions★ by the end of 2027. An additional highlight was a deep-dive into how bp manages risks associated with the integration of acquisitions.

Against the backdrop of an ever-changing regulatory environment, the committee has engaged with management to assess bp's approach to new sustainability reporting and the requirements of the new UK Corporate Governance Code 2024, receiving regular updates on implementation and plans for compliance.

We spent time with the trading and shipping team (now the supply, trading and shipping team) in Houston, US and our business and technology centers in Pune, India, both being strategically significant areas of bp's business. Read more on **page 83**. The committee continues to engage with other stakeholders where appropriate, including through regulatory inspections when they occur.

On behalf of my colleagues on the committee, I would like to extend my thanks for the continued professional support and focus of effort by management and our various advisers during a year where bp delivered strong performance in some areas but had some challenges in others. We look forward to continuing this journey through 2025.

Role of the committee

The committee monitors the effectiveness of the group's financial reporting, including ESG and climate-related financial disclosures, as well as systems of internal control and risk management as allocated by the board. It also monitors the integrity of the external and internal audit processes.

This report describes how bp has approached compliance with the provisions of the FRC's Audit Committees and the External Audit: Minimum Standard.

Key responsibilities

A summary of the committee's terms of reference is on **page 335** and the full terms of reference can be viewed at **bp.com/governance**.

Tushar Morzaria
Committee chair
6 March 2025

Financial expertise

The board is satisfied that
- Tushar Morzaria, the chair of the committee, has recent and relevant financial experience as required by the UK Corporate Governance Code and that he is competent in accounting and auditing in accordance with the FCA's Disclosure Guidance and Transparency Rules.
- The committee has an appropriate and experienced blend of commercial, financial and audit expertise to assess the issues it is required to address, as well as competence in the relevant sector in which bp operates.
- As a US foreign private issuer, the committee meets the independence criteria provisions of Rule 10A-3 of the US Securities Exchange Act of 1934, and Tushar Morzaria can be regarded as an audit committee financial expert as defined in Item 16A of Form 20-F.

b Target first introduced in bp's first quarter 2024 group results announcement referred to as cash costs savings. Cash costs has the same meaning as underlying operating expenditure★.

Activities during the year

Monitoring the integrity of financial reporting and assurance

- Through monitoring and reviewing that bp's financial statements and formal announcements relating to bp's financial performance are clear and appropriate, the committee oversees the integrity of our financial reporting.
- Management's application of key accounting policies and recommendations on financial reporting judgements was carefully considered, with the committee concluding that these matters were appropriately addressed in the financial statements.
- The committee oversaw change in bp's reporting processes, playing a key role in reviewing the governance, assurance and reporting arrangements for trading statements, which were introduced for the first quarter of 2024 with the aim of providing performance insights to investors ahead of the release of quarterly results.
- The committee monitored progress and reporting on cost savings.

Going concern, viability and fair, balanced and understandable considerations

The committee reviewed the company's going concern assumption and longer-term viability statement. In determining and recommending to the board that it was appropriate to adopt the going concern basis of accounting and the longer-term viability of the company, the committee considered carefully (and challenged constructively where appropriate) for example certain enhancements to the longer-term viability statement as found on **page 113**.

The committee received an update from management on the verification process for the bp Annual Report and Form 20-F in support of its recommendation to the board that the annual report was fair, balanced and understandable. The bp Annual Report and Form 20-F was comprehensively reviewed with input from subject matter experts and the external auditors. The committee's review included consideration of bp's non-financial disclosures such as the Task Force on Climate-related Financial Disclosures (TCFD) that are made in compliance with the UK Listing Rules. **TCFD**

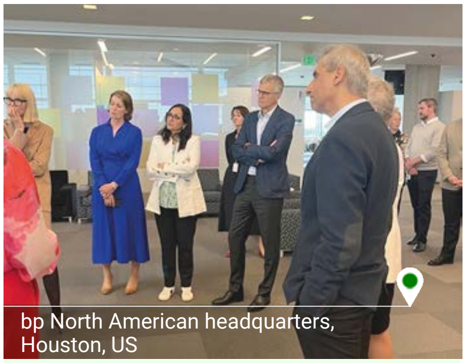
Maintaining resilience through systems of internal control and risk management

- The committee oversaw risk management and internal control processes, routinely reviewing and monitoring principal risks allocated to it by the board through a combination of business or function reviews and focused engagement with key stakeholders.
- Through a deep-dive update, the committee discussed bp's approach to acquisition integration. The session focused on the implementation of revised policies and requirements to manage risk and reduce complexity in aligning new acquisitions with bp's control environment.
- Through supply, trading and shipping updates, the committee reviewed risks to trading such as market, liquidity, credit, operational and people risks and control items. In light of the changing macro and energy price environment, the committee considered the LNG hedging strategy ahead of the winter period, and reviewed and challenged the longer-term outlook for energy prices against bp's price assumptions.
- The committee reviewed the affordability of distributions, taking into account factors such as whether sufficient distributable reserves are available.
- In addition, the committee received:
  - updates on the systems in place to assess fraud risk and the controls in place to manage and mitigate identified risks.
  - an update on compliance with business regulations, together with additional briefings during the year on technical accounting updates and developing ESG disclosures. **TCFD**
- The committee remained prepared for regulatory developments, including receiving updates on the consideration of enhancements to bp's risk management and internal control framework as a result of the new 2024 UK Corporate Governance Code, and received updates on implementation progress.

Effectiveness of risk management and systems of internal control

The committee reviewed and challenged management on the effectiveness of the system of internal control and agreed that it did not require further action nor were there any significant failings or weaknesses to report. As part of this assessment the committee considered internal audit's annual review of internal control and risk management, together with an assessment of it from management. Further details can be found on **pages 112-113**. The committee also discussed internal controls and financial reporting processes during the year, challenging control gaps identified and subsequent actions to remediate, and reviewed progress towards addressing deficiencies that had been previously identified in relation to manual journal controls. Further details on internal controls in place for financial reporting can be found on **page 336.**

In addition, the committee received updates on the evolution and enhancement of non-financial reporting controls and assurance, such as first and second line of defence activities, to take into account the expected increase in new reporting obligations. **TCFD**


bp North American headquarters, Houston, US

US site visit – June 2024

The committee engaged with a range of internal stakeholders during the board's visit to the US in 2024. They toured the supply, trading and shipping activities in Houston, an important part of bp's portfolio, with a focus on biogas, natural gas and power, and met with the local leadership team.


bp office in Pune, India

India site visit – September 2024

During the committee's visit to India, the directors met internal stakeholders based in Pune, ending with a session with the local leadership team. As part of their floor walks across bp's sites, the committee engaged with the finance, business and technology team on their growth story, portfolio and accomplishments.

Key

TCFD	Information that supports TCFD Recommendations and Recommended Disclosures in relation to Governance (see **pages 42-45**)

Audit committee continued

Overseeing the relationship with external and internal audit

- On the recommendation of the committee, the board will propose the reappointment of Deloitte as our external auditor to shareholders at the 2025 annual general meeting. The external auditor's independence and objectivity were reviewed and monitored by the committee using a combination of factors, including assurances provided to it by the external auditor, the level of non-audit fees, and the timeline for lead audit partner rotation and re-tender of audit services. The committee was satisfied with the audit team's effectiveness, service quality and commitment, including that the external auditor provides constructive challenge to management. In support of this, the committee received reports from the external auditor that covered insights from their audit work, actions taken to address the FRC's annual report on the external auditor, and the inspection results of the external auditor's quality control procedures. In addition, the committee received reports from management, which included a survey seeking internal stakeholder feedback on the external auditor's performance and bp's commitment to the audit. The main measurement criteria covered planning and scope, robustness of audit, independence and objectivity, quality of delivery, quality of people and service, and value-added advice.
- The committee met privately with the external auditor during the year, and in addition reviewed, approved and monitored progress against the external audit plan, considering materiality levels, audit risks, scoping changes, and resourcing. The committee is satisfied that the external auditor has full access to staff and records.
- The committee continued to monitor and review the effectiveness and capabilities of the internal audit function. This included for example reviewing and approving the internal audit plan in the context of bp's principal risks and discussing an update on actions taken in response to the recommendations of an external quality assessment conducted by PwC in 2022. The committee concluded that the function had independent, unrestricted scope, access to information, and sufficient resources to fulfil its mandate. They met privately with the SVP internal audit, discussed regular updates on internal audit activities and where appropriate challenged management's response and progress made on the closure of findings.

A summary of the external audit approach, including audit risks, is set out in the independent auditor's report on **pages 116-133**.

Lead audit partner rotation and re-tender of audit services

The external auditor must rotate the lead audit partner every five years and other senior staff every five to seven years.

The company complies with the Statutory Audit Services for Large Companies Market Investigation (Mandatory Use of Competitive Tender Processes and Audit Committee Responsibilities) Order 2014, which requires bp to tender the audit at least every 10 years.

External audit services were last tendered in 2016 and the external auditor has been in that role since 2018 (seven years). It is anticipated that a re-tender will be completed by 2026, for the 2028 audit. The committee believes that the timeline is in the best interests of shareholders, providing an appropriate balance between knowledge of controls and risks, maintaining audit quality, independence and objectivity and value for money.

Oversight of audit fees and non-audit services

The committee reviewed and approved the audit services fee and terms of engagement for the external auditor while retaining oversight of bp's policy on non-audit services and the review and approval of non-audit services.

The total amount of audit and non-audit fees paid to Deloitte for 2024 is set out in **Financial statements – Note 36**. The committee is satisfied that the audit fee is appropriate in respect of the audit services provided. The majority of non-audit fees relate to work of an assurance nature.

The non-audit services policy safeguards audit objectivity and independence through the prohibition of non-audit tax services being provided by the external auditor, the limitation of audit-related work which falls within defined categories, and by stating that the auditor may not perform non-audit services that are prohibited by the SEC, Public Company Accounting Oversight Board (PCAOB), International Auditing and Assurance Standards Board (IAASB) or the FRC.

The external auditor is considered for permitted non-audit services only when its expertise and experience of bp are important. Approvals for individual engagements of pre-approved permitted services below certain thresholds are delegated to the SVP accounting, reporting and control or the CFO. More information is outlined in the principal accountant's fees and services on **page 337**.

Examples of how key accounting judgements and estimates were considered and addressed, and how relevant accounting policies have been applied

Key accounting judgements and estimates	Audit committee activity	Conclusions/outcomes
Impact of climate change and the energy transition TCFD		
Climate change and the transition to a lower carbon economy may have significant impacts on the currently reported amounts of the group's assets and liabilities and on similar assets and liabilities that may be recognized in the future.	• Reviewed management's best estimate of oil and natural gas price assumptions for value-in-use impairment testing and investment appraisal. • Reviewed management's determination that its best estimate of oil and natural gas prices is in line with a range of transition paths consistent with the goals of the Paris climate change agreement.	• Management's revised best estimate of oil and natural gas prices are in line with a range of transition paths consistent with the goals of the Paris climate change agreement. • See Financial Statements – Note 1 for more details on how bp applies carbon pricing in its impairment testing, sensitivity analyses estimating effects of changes in net revenue and changes in the expected timing of decommissioning.

Key accounting judgements and estimates	Audit committee activity	Conclusions/outcomes
Provisions		
The group holds provisions primarily for decommissioning, environmental remediation and litigation. The most significant provision is for the future decommissioning of oil and natural gas production facilities and pipelines. Estimation uncertainty exists as most of these events are many years in the future. Assumptions are made by bp in relation to cost estimation, settlement dates, technology, legal requirements and discount rates. There is also a risk that decommissioning obligations from previously divested assets revert to bp.	• Received briefings on decommissioning (including the process for managing the risk of decommissioning reversion), environmental, asbestos and litigation provisions. These included the requirements, governance and controls for the development and approval of cost estimates and provisions in the financial statements. • Reviewed and challenged the group's discount rates for calculating provisions.	• Decommissioning provisions of $11.8 billion were recognized on the balance sheet at 31 December 2024. • The discount rate used by bp to determine the balance sheet obligation at the end of 2024 was a nominal rate of 4.5% based on long-dated US government bonds, an increase of 0.5% from 2023.
Recoverability of asset carrying values		
Determination as to whether and how much an asset (including exploration intangibles), cash generating unit (CGU) or group of CGUs containing goodwill is impaired involves management judgement and estimates on uncertain matters such as future commodity prices, discount rates, production profiles, reserves and the impact of inflation on operating expenses. Judgement is required to determine whether it is appropriate to continue to carry intangible assets related to exploration costs on the balance sheet.	• Reviewed policy and guidelines for compliance with oil and gas reserves disclosure regulation, including the group's reserves governance framework and controls. • Reviewed and challenged the group's oil and gas price assumptions. • Reviewed and challenged the group's discount rates for impairment testing purposes. • Impairment charges, reversals and 'watch-list' items were reviewed in the quarterly due diligence process.	• The group's price assumption for Brent oil and for Henry Hub gas were updated as set out on **page 20** and Financial Statements – Note 1. • Sensitivity analyses estimating the effect of changes in net revenue and discount rate assumptions have been disclosed in Financial Statements – Note 1. • Net impairment charges of $5.2 billion as disclosed in Financial Statements – Note 4. • Exploration intangibles totalled $4.4 billion at 31 December 2024.
Taxation		
Computation of the group's income tax expense and liability, the provisioning for potential tax liabilities and the level of deferred tax asset recognition are underpinned by management judgement and estimation of the amounts which could be payable. Judgement is also required when determining whether a particular tax is an income tax or another tax type.	• Received regular updates on the group's tax risk exposures and deferred tax asset recognition. • Reviewed the judgements exercised over tax risk provisioning as part of its annual review of key provisions.	• Deferred tax assets of $5.4 billion were recognized on the balance sheet at 31 December 2024. • The calculation of tax risk provisions is consistent with IAS 37 and IFRIC 23.
Pensions		
Accounting for pensions and other post-employment benefits involves making estimates when measuring the group's pension plan surpluses and deficits. These estimates require assumptions to be made about uncertain events, including discount rates, inflation and life expectancy.	• Reviewed and challenged the group's assumptions used to determine the projected benefit obligation at the year end, including the discount rate, rate of inflation, salary growth and mortality levels.	• At 31 December 2024, surpluses of $7.5 billion and deficits of $4.9 billion were recognized on the balance sheet in relation to pensions and other post-employment benefits. • The method for determining the group's assumptions remained largely unchanged from 2023. The values of these assumptions and a sensitivity analysis of the impact of possible changes on the benefit expense and obligation are provided in Financial Statements – Note 24.
Supplier finance arrangements		
The group's trade payables include certain supplier finance arrangements that utilize letter of credit facilities and promissory notes. Judgement is required to assess trade payables subject to supplier financing 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.	• Received a briefing on the group's supplier finance arrangements. • Reviewed the group's proposed enhanced disclosures in relation to Amendments to IAS 7 ' Statement of Cash Flows' and IFRS 7 'Financial Instruments: disclosures' relating to supplier finance arrangements.	• bp had liabilities of $7.4 billion, $1.8 billion and $0.4 billion, respectively, in respect of letters of credit, promissory notes and reverse factoring arrangements that are presented within trade and other payables at 31 December 2024. • The disclosures required by the Amendments to IAS 7 ' Statement of Cash Flows' and IFRS 7 'Financial Instruments: disclosures' relating to supplier finance arrangements are included in Financial Statements – Note 29.
Derivatives		
For its level 3 derivative financial instruments, bp estimates their fair values using internal models due to the absence of quoted market pricing or other observable, market-corroborated data. Judgement may be required to determine whether contracts to buy or sell commodities meet the definition of a derivative, in particular LNG contracts.	• Received a briefing on the group's trading risks and reviewed the system of risk management and controls in place. • Reviewed the control process and risks relating to the trading business. • Received updates on accounting judgements on LNG contracts.	• bp has assets and liabilities of $16.0 billion and $14.4 billion, respectively, recognized on the balance sheet for level 3 derivative financial instruments at 31 December 2024, mainly relating to the activities of the trading & shipping function. bp's use of internal models to value certain of these contracts has been disclosed in Financial Statements – Note 1. • bp considers that contracts to buy or sell LNG do not meet the definition of a derivative under IFRS.

★ See glossary on **page 351**

People, culture and governance committee

Helge Lund
People, culture and governance committee chair

"2024 has been a busy year for the committee, with a strong focus on leadership succession and development."

Meetings and attendance

The committee met seven times during 2024. The CEO and EVP people, culture & communications regularly attend these meetings.

Non-executive directors	Six scheduled meetings	One ad hoc meeting
Helge Lund: member (from July 2018), chair of the committee (from September 2018)	6/6	1/1
Dame Amanda Blanc: member[a]	6/6	0/1
Dr Johannes Teyssen: member (from April 2024)	3/3	1/1
Hina Nagarajan: member (from April 2024)	3/3	1/1
Paula Rosput Reynolds: member (until April 2024)[b]	2/3	0/0
Sir John Sawers: member (until April 2024)	3/3	0/0

a Dame Amanda was unable to attend the ad hoc meeting in October due to an existing external commitment.
b Paula was unable to attend the scheduled meeting in February due to an existing external commitment.

Chair's introduction

Dear fellow shareholders,

I am pleased to present the people, culture and governance committee (PCGC) report for the year ended 31 December 2024.

2024 has been a busy year for the committee, with a strong focus on leadership succession and development. This is to position bp to leverage the skills and experience we have in pursuit of our strategy.

In 2023 our emergency executive succession plans were tested – successfully – with the appointments of Murray Auchincloss and Kate Thomson into interim positions, prior to their permanent appointments as CEO and CFO in January and February 2024 respectively.

Following the board's decision in January 2024 to appoint Murray Auchincloss as our permanent CEO, the committee oversaw the launch of a new leadership team structure.

Succession and development plans for executive roles across the short, medium and long term have been refreshed and are routinely reviewed by the committee. The committee also revised emergency succession plans, which will continue to be assessed and reviewed for the key CEO and CFO roles.

Non-executive director succession was also at the forefront of the committee's agenda in 2024, seeking candidates who will fulfil the agreed criteria for emerging vacancies on our board, with a particular focus on a permanent successor with the experience to take on the chairmanship of the remuneration committee and former executives with global, transformation experience in large, complex industrial companies both from within and outside of the sector. This helps us to ensure we can maintain an effective board with the necessary skills and experience to drive forward bp's strategy.

We recognize that a strong culture – particularly a culture of caring for others and speaking up – is vital in times of change. In 2024, the committee changed its name from the people and governance committee to the PCGC to reflect its broader remit in relation to culture and engagement, including the monitoring of bp's 'Who we are' culture frame and how it is being embedded.

A strong culture requires continuous focus and the committee's enhanced oversight of the effectiveness and continual embedding of bp's culture frame will provide valuable insight about bp's culture and areas where further focus is required.

On behalf of my colleagues on the committee, I would like to thank the management team working to support and advise us in the delivery of the committee's priorities and look forward to building on the substantial progress made.

Role of the committee

The committee seeks to ensure that the composition and structure of the board and leadership team remain effective. It also monitors the balance of skills, knowledge, experience and diversity required. The PCGC oversees the development of a diverse pipeline for succession to the board and leadership team through succession planning and monitoring development plans for bp leaders and beyond.

The committee provides oversight of bp's culture and its alignment with our 'Who we are' culture frame, and monitors sentiment of the workforce.

The process for the nomination, induction and orderly succession of candidates for the board, the leadership team and the company secretary role are led by the committee, as is the annual board and committee performance review.

Key responsibilities

The committee's full terms of reference can be viewed at **bp.com/governance**.

Helge Lund
Committee chair
6 March 2025

Activities during the year

Planning for the future: the board and bp's leadership team

- As set out in our 2023 report, the committee endorsed the appointments of Murray Auchincloss and Kate Thomson as CEO and CFO, respectively in 2024. By routinely reviewing succession plans for the board, bp leadership team and senior leadership positions, and also taking into account the skills and diversity profiles we aspire to achieve for our leaders, the PCGC prepares and shapes bp's leadership structure to be fit for the future.
- The committee oversaw a proposed restructuring of bp's leadership team under the new CEO, reflecting the importance of organizational focus, simplification, and value growth. The new leadership team structure was effective from April 2024. Read more on **page 74**.
- Through updates from the EVP people, culture & communications, the committee oversees development plans for bp's senior leaders and emerging talent and their alignment with executive succession planning over different timescales. Development plans identify critical experience and roles to bolster the skills of individuals with executive potential.
- The committee assessed non-executive candidates against agreed criteria for non-executive roles[a] to equip the board with the skills and diversity needed to meet current and future needs, focusing on candidates primarily from the UK and US with industry, safety, operational and remuneration committee experience.

Diversity: continued progress

- Early in 2024, the committee recommended the appointment of Kate Thomson as CFO for approval by the board. Kate is bp's first female CFO. Dame Amanda Blanc was also appointed as SID, meaning that 50% of senior positions on bp's board are now represented by women, and as a whole the board has 55% female representation – this aligns with our board diversity, equity and inclusion (DE&I) policy aspiration towards gender parity on the board.
- The committee proposed amendments to the board DE&I policy to better inform the board and committee's approach to succession planning, recognising the benefits of diversity to decision-making and outcomes.
- The board DE&I policy applies to the board and its committees, and complements bp's wider diversity policies, the group's values, code of conduct and sustainability frame. It includes board gender and ethnicity representation targets aligned with the UK Listing Rules and a commitment by directors to increase their understanding of all aspects of diversity, equity and inclusion. Read more at **bp.com/governance**.

Strengthening oversight of culture and the voice of the workforce

- Following the standing down of the culture-focused 'Who we are' oversight committee, the PCGC oversaw the roll-out of the refreshed bp conflicts of interest policy, which incorporates bp's requirements on relationships at work.
- The committee has undertaken work relating to its broadened oversight of engagement, culture, and how culture has been embedded, which included monitoring feedback from the workforce on the refreshed conflicts of interest policy.
- The committee's oversight of bp's culture was enhanced through private sessions with bp's head of ethics and compliance (E&C) who has accountability to, and direct channels of communication with, the PCGC. The committee approves the appointment and termination of the head of E&C and reviews and recommends their remuneration to the remuneration committee.
- The workforce engagement programme (WFEP) was refined to incorporate culture-related questions, and quarterly culture-focused sessions were implemented to help the committee understand the workforce's experience of the 'Who we are' culture frame. The committee provided workforce views and feedback to the board, strengthening consideration of workforce views in board discussions and decisions. The committee concluded that the WFEP is the appropriate mechanism for workforce engagement, given the activities and structure of bp. Read more on **page 78**.

Enhancing the effectiveness of the board

- The board performance review in 2023 highlighted the importance of the board's role in monitoring culture as an important underpin of the company's performance. This led to the broadening of the committee's remit in relation to culture and engagement as already discussed within this report. The 2023 review also triggered a comprehensive programme of strategy workshops, comprising discussions between the board and members of the bp leadership team at each board meeting during 2024. This concluded with the announcement on 26 February 2025 that presented a fundamental reset of the company's strategy.
- For 2024, the annual board and committee performance review was facilitated externally by Independent Board Evaluation[b] (IBE). Inputs were sought by IBE from board members, key executives and advisors, culminating in a discussion about the report at our board meeting in March 2025.
- Following this discussion, the board agreed to implement actions across the following four areas, with the monitoring and tracking of these actions delegated to the company secretary:
  - Succession planning, induction and leadership interactions: succession planning will focus on the key roles and skills required within the board and senior management for the new strategy. This will include the creation of further opportunities or interactions with management who have high leadership potential.
  - Performance management culture: ensure that bp has a culture where members of the leadership team are held to account for performance delivery and capital allocation.
  - Risk management and governance: more in-depth discussions around emerging risks and their potential impact on organizational resilience and sustainability.

Diversity statistics and outcomes

As at 31 December 2024, 55% of the board were women, two senior board positions were held by women and three directors identified as being from a minority ethnic background, which exceeds the UK Listing Rules targets. For further numerical data on the ethnic background and gender identity or sex of bp's board and executive management, in line with the UK Listing Rules, see **page 111.**

As at 31 December 2024, senior management, defined as the leadership team (being the first layer of management below board level) and the company secretary, in accordance with the UK Corporate Governance Code 2018, and their direct reports comprised 50% women (2023 51%) and 29% Black, Asian and other ethnic minority individuals (2023 26%).

bp has an ethnicity ambition to 2025, read more about this on **page 58.**

a The committee engaged Heidrick & Struggles, Korn Ferry, Spencer Stuart, Egon Zehnder and MWM Consulting in support of search activity for new board candidates. None of the search agents have any connection with the company or individual directors, save that Spencer Stuart supports on executive recruitment and Egon Zehnder provides advice and support on bp's executive development programme.

b There is no connection between Independent Board Evaluation and either bp or the individual directors.

Directors' remuneration report

Tushar Morzaria
Interim remuneration committee chair

"2024 has been a challenging year operationally but one in which bp has set the foundations for growth as a simpler, more efficient business."

Meetings and attendance

The chair and the chief executive officer (CEO) are standing attendees, except for matters relating to their own remuneration. The CEO is consulted on remuneration of the chief financial officer (CFO) and the leadership team, and receives input from the committee on remuneration across the wider workforce. Both the CEO and CFO are consulted on matters relating to the group's performance and the metrics adopted for each performance cycle.

bp's EVP people, culture & communications, SVP reward, external advisors and other executives may attend where necessary. The committee consults other board committees on the group's performance and on issues relating to the exercise of judgement or discretion as necessary.

The committee met seven times during 2024 and all directors attended each meeting.

Non-executive directors	Six scheduled meetings	One ad-hoc meeting
Tushar Morzaria: member (September 2020), interim chair of the committee (April 2024)[a]	6/6	1/1
Paula Rosput Reynolds: member (September 2017), chair of the committee (May 2018 to April 2024)[a]	2/2	1/1
Dame Amanda Blanc: member	6/6	1/1
Pamela Daley: member	6/6	1/1
Melody Meyer: member	6/6	1/1

a Paula Rosput Reynolds stepped down from the board at the 2024 AGM. Tushar Morzaria was appointed as interim remuneration committee chair from this date.

Key

TCFD	Information that supports TCFD Recommendations and Recommended Disclosures in relation to Governance (see **pages 42-45**)

Role of the committee

The role of the committee is to determine and recommend to the board the remuneration policy and to set chair, executive director and leadership team remuneration. In determining the policy, the committee takes into account various factors, including wider workforce remuneration, structures and alignment of reward with performance, thus promoting the long-term success of the company. The committee also reviews workforce remuneration and monitors related policies, satisfying itself that incentives and rewards are aligned with bp's goals and culture.

Key responsibilities

A summary of the committee's terms of reference is on **page 335** and the full terms can be reviewed at **bp.com/governance**.

Key areas of focus in 2024

- **Change in leadership** – set the remuneration terms for the CEO and CFO, who were appointed to their respective roles on 17 January 2024 and 2 February 2024.
- **Workforce engagement** – engaged with the wider workforce on performance, reward and wellbeing. This included holding a workforce engagement programme session in May 2024, where selected employees were invited to discuss bp's approach to reward and employee engagement.
- **Remuneration outcomes** – agreed the outcomes of incentive awards for executive directors, including reviewing performance 'in the round' and determining whether discretion should be exercised. Monitored in-flight progress of equity and bonus awards.
- **Performance measures** – discussed and agreed the performance measures for the 2024 annual and long-term performance scorecards to ensure alignment with bp's strategy. This included reflecting on our sustainability measures and seeking input from the safety and sustainability committee. **TCFD**
- **Framework on fatalities** – reflected on the impact of fatalities on annual bonus outcomes and introduced a framework to help guide decisions going forward.
- **Merit-based reviews** – reviewed pay for performance arrangements for the leadership population in line with bp's reward principles.

Contents

Chair's introduction

Dear fellow shareholders,

On behalf of the board, I am pleased to present our 2024 directors' remuneration report.

This report provides an overview of our current remuneration policy, details the remuneration decisions we have made in respect of the year ended 31 December 2024 and provides a summary of how the policy is being implemented this year.

As this is my first report since being appointed as interim chair of the remuneration committee in April 2024, I would like to take this opportunity to thank my predecessor, Paula Rosput Reynolds, for her exemplary leadership since 2018.

I intend to continue in my interim role until at least the 2025 AGM in order to provide a robust and timely handover with the incoming remuneration committee chair once appointed to the board.

Business performance

2024 has been a challenging year operationally but one in which bp has set the foundations for growth as a simpler, more efficient business. Significant progress has been made in 2024 to focus, high grade and reshape bp's portfolio. bp delivered operating cash flow★ of $27.3 billion and adjusted EBITDA★ of $38.0 billion with upstream production 2.0% higher than in 2023.

There were also a number of strategic milestones, with final investment decision (FID) taken on 10 major projects★ and establishing key strategic partnerships.

In July 2024, bp made the FID on the Kaskida project in the Gulf of America, demonstrating our long-term commitment to delivering reliable and affordable energy. Further, progress was made in Iraq and India, where we agreed new access on a material scale. We have also made progress with our renewables business. Significant among them were our holdings in Lightsource bp and bp Bunge Bioenergia being raised to 100%. In addition, the proposed joint venture with JERA Co., Inc. will create a leader in offshore wind development and help grow the scale of the business in a capital-light way for bp.

Alongside this strategic progress, bp delivered a $0.8 billion reduction in structural costs★ during the year, creating a strong platform for 2025.

Nevertheless, it was a difficult year in parts of our customers & products businesses, particularly in refining. Margins were lower and the significant power outage at our refinery in Whiting had a direct impact on our operational and financial performance during the year, which is in turn reflected in remuneration outcomes.

The macroeconomic environment and lower prices added to a challenging backdrop.

Incentive outcomes

2024 annual bonus

The 2024 annual bonus was based on a scorecard of performance measures across three categories: safety and sustainability (30% weight), operations (20% weight) and financials (50% weight).

Safety and sustainability

Safety continues to come first in everything we do at bp and we place extensive focus on ensuring that our operations run safely every day.

Safety performance is measured against the number of tier 1 and tier 2 process safety events★ (7.5% weight each). The measures are assessed independently by the safety and sustainability committee, thus providing appropriate focus on tier 1 delivery.

The committee is pleased to report that the number of tier 1 events was lower in 2024 compared to the prior year and continues the positive trend we have seen in recent years. In contrast, there was an increase in the number of tier 2 events compared to the prior year, with 35 events in 2024. This increase has negatively impacted results delivering a combined outcome of 67% of maximum.

At the start of 2024, a framework was introduced to help guide the committee's decisions on the impact of fatalities on remuneration outcomes. The framework was intended to avoid formulaic outcomes vis-à-vis fatalities, instead providing guardrails for informed judgement in the conclusions we make, while also recognizing that every incident is different and should be reflected upon individually.

I am saddened to report that there was a fatality in October 2024 in the newly acquired bp bioenergy business. Details of how the framework has been applied in respect of this year's bonus outcomes are provided on **page 98**.

We continue our focus on sustainability. This was the first year that sustainability performance was measured against operated carbon emissions (15% weight). bp's performance was strong, delivering 1.8Mte ahead of our scorecard target, which resulted in an outcome of 84% of maximum.

Operations

The reliability★ and availability★ of our plants and refineries were impacted by operational challenges throughout the year, including the power outage at Whiting in February. This was partly offset by strong performance in other areas of the business, such as North Africa. The bonus outcome, however, was nil for this measure.

For 2024, we introduced a new operations measure that focused on earnings growth in our transition growth★ engines. Significant headwinds in certain parts of the business, along with the continued operational challenges within our customers & products businesses, resulted in this component of the scorecard yielding a nil outcome.

Financials

We have two measures of financial performance: annual adjusted EBITDA★ and modified free cash flow★[a].

In line with policy, we reflect underlying performance and hence the targets for both financial measures are adjusted for the actual price environment.

Despite recovery in the latter half of the year, financial performance was impacted by the operational challenges cited elsewhere. Adjusted EBITDA delivery at $38.0 billion and modified free cash flow at $12.5 billion were both below threshold resulting in nil bonus outcomes.

Overall result

The formulaic outcome of the annual bonus was below target at 0.45 out of 2.00 (22.5% of maximum).

The committee reflected on this score and determined it was appropriate for executive directors and the senior leadership of the company covering approximately 300 employees. We did, however, apply discretion and award a higher score (but below target) to the wider workforce covering over 38,000 eligible employees in recognition of motivation and engagement levels. bp is undergoing enormous transformation and a shrinking workforce will carry significant accountability.

2022-24 performance shares

The 2022-24 performance shares were measured against relative TSR (20% weight), return on average capital employed★ (ROACE) (20% weight), adjusted EBIDA per share compound annual growth rate (CAGR)★ (20% weight) and strategic progress (40% weight).

rTSR

For relative TSR, bp placed sixth in the comparator group which resulted in nil vesting for this measure.

Financials

Financial performance was strong over the three-year performance period and both performance measures achieved full vesting. The 2022-24 average ROACE was 20.9%, significantly outperforming expectations. Similarly, adjusted EBIDA per share CAGR performance of 11.1% exceeded the level required for maximum vesting.

a The directors' remuneration report in the *bp Annual Report and Form 20-F 2023* refers to an 'adjusted free cash flow' measure in the 2024 annual bonus scorecard. This has the same definition as the 'modified free cash flow' measure reported here.

★ See glossary on **page 351**

Strategic progress

Strategic progress was measured based on a balance of quantitative assessment and qualitative judgement against the three strategic pillars set in 2022. This was supplemented with the committee's judgement on overall progress in the three years of this plan, especially in the final year of the plan.

As set out in the 2023 directors' remuneration report, in terms of the quantitative assessment, the committee also took into account value generation over the period, rather than focusing solely on volume metrics for each pillar of this measure. Further, the committee also considered the various actions taken by management, contextual to our evolving strategy during the three-year period.

We provide a detailed view of the committee's review of strategic progress on **pages 100-101.**

Having considered the above, the committee determined that while commitments set out in early 2022 were not fully realized, good progress had been made. An outcome of 66% of maximum was felt appropriate for this measure.

Overall result

Overall, performance share vesting for the 2022-24 cycle was 66.5% of maximum. The committee believes that this final outcome is an appropriate reflection of actual performance during the period and therefore has not applied any further discretion.

In determining the bonus and equity outcomes the committee has reviewed incentives holistically taking into consideration the total remuneration for Murray and Kate (2024 single figures of £5.4 million and £1.9 million respectively). We determined that this quantum for individuals managing a company of bp's size and scale felt appropriate for 2024, taking into account both the performance of the company and shareholder experience.

Looking ahead to 2025

Annual pay review

Kate Thomson was appointed to the board on 2 February 2024 and her remuneration arrangements were set in line with our policy. Her base pay was set at £800,000, which was at a lower level than her predecessor and was based on her being newly appointed to the board, while also allowing for progression in role over time.

In last year's report, we noted that any future adjustment to Kate's base pay may exceed the percentage for the wider workforce subject to performance in role. Since then, the committee has reflected on Kate's performance and her competitive positioning against the policy-determined peer group. During a period of significant change for bp, Kate performed strongly and displayed impressive leadership skills. She has clearly proven her capability over the course of the year.

In light of Kate's progression in role and very strong performance to date, the committee decided that it would be appropriate to increase her base pay by 8%. This will be effective from the 2025 AGM.

For Murray Auchincloss, his base pay will increase by 4%, which is in line with the increase being awarded to the wider workforce.

When reflecting on pay decisions for executive directors, the committee remains mindful of the transformation drive in the company as well as the approach being taken for our wider workforce pay. For 2025, the average salary increase in the UK will be 4%. Adjustments in other jurisdictions vary by local conditions. All employees in the UK earn at least the UK Living Wage.

Review of performance measures

For 2025, in line with policy, we have reviewed and aligned the measures of the bonus and performance share plan against our reset strategy, as set out on 26 February.

Alignment with strategy and financial frame

As outlined by Murray and Kate at the Capital Markets Update in February, bp has reset its strategy, simplifying our forward-looking commitments with four primary targets; adjusted free cash flow★ growth, structural cost reduction, ROACE and net debt★. You will see that, where appropriate, these targets form the basis for our incentive scorecards.

Consequently, the earnings measure in the annual bonus scorecard will be replaced with a structural cost reduction measure (25% weight). By way of balance, and to signal the importance of cash delivery, the modified free cash flow measure will increase in weight from 25% to 30%.

Reflecting the focus of our strategy, we have removed the transition growth engine growth measure, and in its place increased the weighting of bp-operated reliability and availability from 10% to 15%. In doing so, we have simplified the scorecard from 6 to 5 measures.

Our focus on safety and emissions has not changed and therefore the current measures and weightings under this category will remain the same.

For performance share awards, we reflected on the appropriate mix of financial measures in the scorecard for 2025-27 – taking into consideration the priorities set out in the strategy update.

To better reflect the importance of cash generation, we have replaced the earnings measure with adjusted free cash flow CAGR★ in our scorecard (20% weight). The committee believes the dual focus of modified free cash flow in the short term and adjusted free cash flow CAGR over the long term is appropriate for the scorecards as they bring focus and are aligned to bp's strategy.

Further, we are proposing to align the ROACE measure with our external commitments, with performance being assessed to the end of 2027 and adjusted for the environment.

All other measures from the 2024-26 plan remain unchanged.

Alignment with stakeholders

During the year, we continued our practice of regular engagement with shareholders. We engaged with our top shareholders and investor bodies, accounting for over 35% of issued share capital, and have taken into consideration their views when determining the 2024 remuneration outcomes and 2025 performance measures. We have tried to strike a balance between broader shareholder experience and executive motivation in determining the overall bonus and share plan outcomes.

Concluding remarks

I hope that you find this year's report a clear account of the committee's application of the remuneration policy during the year.

On behalf of the committee, I would like to extend my thanks to our various advisors, shareholders and investor bodies for their input and engagement during the year. While 2024 was a year of mixed performance, we are thankful for the support received and look forward to continuing this journey in 2025.

At the forthcoming AGM there will be an advisory vote in respect of the directors' remuneration report and I look forward to your continued support of remuneration at bp.

Tushar Morzaria
Interim chair of the remuneration committee
6 March 2025

Remuneration at a glance

Key performance highlights in 2024

$27.3bn
operating cash flow★
Resilient financial performance

$38.0bn
adjusted EBITDA★

+2%
upstream production
2,358mboe/d 2024 production

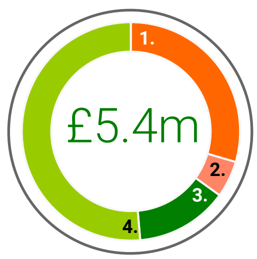
- Agreed to form offshore wind JV with JERA Co., Inc., divesting non-core assets.
- 100% ownership of bp bioenergy and Lightsource bp.
- Delivered $0.8 billion structural cost reduction★.
- Start-up of a major project★ and sanctioned a further 10 projects.

Total remuneration in 2024

- 1. Salary and benefits
- 2. Cash allowance in lieu of pension
- 3. Annual bonus
- 4. Performance shares

Single figure

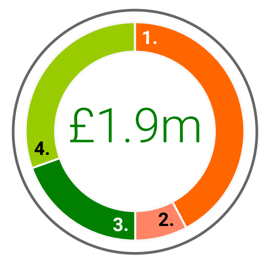
Chief executive officer



35%
Fixed pay

65%
Variable pay

Chief financial officer

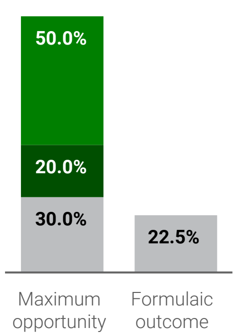


50%
Fixed pay

50%
Variable pay

Pay outcomes in 2024

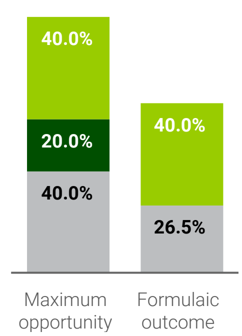
Annual bonus 2024



22.5%
of maximum
formulaic outcome

Safety and sustainability ■ Operations ■ Financials

Performance shares 2022-24



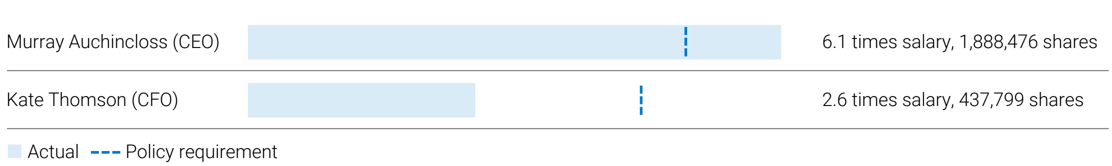
66.5%
of maximum
formulaic outcome

Strategic progress ■ rTSR ■ Financials

Application of discretion
The committee determined not to exercise discretion in determining the outcomes for the annual bonus and performance shares, reflecting on performance and the broader shareholder experience during the performance period.

Alignment with shareholders

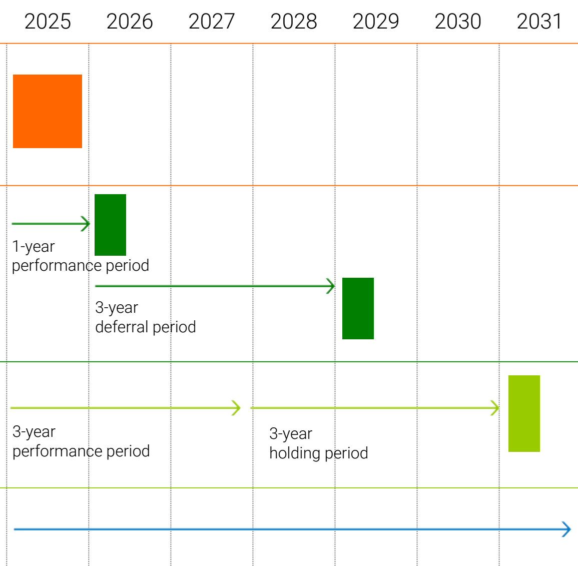
Share ownership
Share ownership is a key means by which the interests of executive directors are aligned with those of shareholders.



★ See glossary on **page 351**

Application of remuneration policy for 2025

Set out below is an illustration of how the remuneration policy will be implemented for 2025.



Fixed pay (salary, pension and benefits)	• Upon appointment in 2024, the CEO's and CFO's salaries were set at £1.45 million and £0.8 million respectively. Their salaries remained unchanged in respect of 2024. • For 2025, Murray's salary will increase by 4% in line with the wider workforce. Kate's salary will increase by 8%, reflecting her performance and development in role since appointment.
Annual bonus[a]	• CEO's max opportunity: 225% of salary. • CFO's max opportunity: 225% of salary. • For 2025, a structural cost reduction measure has been introduced to the bonus scorecard **(see below)**.
Performance shares	• CEO's max opportunity: 500% of salary. • CFO's max opportunity: 450% of salary. • For 2025-27, an adjusted free cash flow CAGR measure has been introduced to the performance shares scorecard **(see below)**.
Shareholding requirement	• In-employment and post-employment guidelines will continue to apply.

a Half the bonus is paid in cash, and half is deferred into bp shares for three years up until 'minimum shareholding requirement' is met. At this point, 67% is paid in cash and 33% is deferred into bp shares.

Alignment of 2025 variable remuneration with strategy

Each year, the committee aims to set a remuneration framework for executive directors that supports and incentivizes the execution of our strategy. For 2025, the performance measures in the annual bonus and performance shares scorecards have been refined to align with our reset strategy. Measures that have been introduced for 2025 have been marked with ▲ below. Further details on the rationale for their inclusion can be found on **pages 104-105.**

	Net zero by 2050 or sooner	Financial frame	Strategy
Annual bonus			
Safety and sustainability (30%)			
Tier 1 and tier 2 process safety events★			●
Operated carbon emissions	●		●
Financials and operations (70%)			
Modified free cash flow★ ($bn)		●	●
Structural cost reductions★ ($bn) ▲		●	●
bp-operated reliability★ and availability★			●
Performance shares			
Cumulative reduction % in operated carbon emissions (15%)	●		
Relative TSR (25%)		●	
ROACE★ (20%)		●	●
Adjusted free cash flow CAGR★ (20%) ▲		●	●
Strategic progress (20%)			●

Directors' remuneration report continued

Engaging with our workforce

As a committee, we spend considerable time on matters relating to performance and remuneration arrangements across the wider workforce. We believe that our people are the key to bp's success and our approach to performance and reward should be fair and consistent across the organization.

Alignment of executive and workforce remuneration

All employees	Element of remuneration	Executive directors
Salary is the basis for a competitive total reward package for all employees, and we conduct an annual salary review for all non-unionized employees. In setting pay budgets, we assess how employee pay is currently positioned relative to market rates, wage inflation, forecasts and business context.	Salary	The salaries of our executive directors are reviewed annually, along the same timeline as the wider workforce. The review of salaries will take into account the same factors considered for the wider workforce. Salary increases for executive directors will typically be at or below the workforce rate, other than in specific circumstances.
We operate different pension plans by location and for those parts of our business where market practice is markedly different, e.g. our retail business. For our population of non-retail employees in the UK, we provide a flexible cash benefits allowance of 20% of salary. The benefits available are aligned with competitive market practice in our different jurisdictions.	Pensions and benefits	Executive directors receive a cash allowance in lieu of pension aligned with the wider workforce (currently 20% of salary). Other than the provisions of car, security and tax preparation related benefits, benefit packages are broadly aligned with those of other employees in the UK.
More than half of the eligible workforce participate in an annual cash bonus plan that multiplies a grade-based target bonus amount by a bp performance factor derived from the bonus scorecard. Select participants may be nominated to receive an uplift to their bonus outcome, reflecting their personal contribution and impact. We operate different bonus plans for those distinct parts of our business where market practice is markedly different.	Annual bonus	The annual bonus for the executive directors is linked to the same bp performance factor as for the wider workforce. Executive directors are not entitled to a bonus uplift linked to individual performance. For executive directors, a portion of any award is deferred into shares for three years. The deferral rate depends on whether the executive director has met their minimum shareholding requirement.
We operate share plans with three-year vesting for all our senior leaders. Opportunity varies across two broad tiers: group leaders (approximately 300) and senior-level leaders (approximately 4,500).	Performance shares	Executive directors are eligible for performance share awards, which are subject to stretching performance targets over a three-year period. An additional three-year post-vesting holding period applies for executive directors.

Other elements of pay

Recognition

energize!, our global recognition platform, is open to all employees for peer-to-peer recognition. The scheme aims to celebrate employee's contributions, highlight behaviours vital to our success and drive a performance edge. In 2024, a total of 38,800 energize! awards were made.

We also operate a spot bonus programme, where individuals or teams can be nominated to receive a one-off cash award to recognize their achievements.

Senior leaders and our executive directors fully participate in the programmes, typically by giving recognition.

Focus@bp

At bp, focus@bp is our internal platform that helps support performance development. The platform enables employees to set dynamic goals, have regular check-ins, give and receive meaningful feedback and grow skills to enable our teams to develop and deliver.

We believe that performance matters, both individually and collectively, and development is key in helping to improve our performance as a business.

focus@bp forms the basis of discussions relating to development or progression and is factored in when making decisions in relation to an individual's remuneration.

All-employee share plan

bp operates an award-winning global ShareMatch programme which is available to over 18,000 employees in 46 countries.

This plan offers our employees the opportunity to invest and share in bp's success, fostering a culture of shared ownership.

At the end of 2024, the participation rate in the scheme was 65% of eligible employees.

★ See glossary on **page 351**

Workforce highlights in 2024

Supporting employees during transformation

Health and wellbeing

Within the context of our ongoing organizational transformation, we have deepened our global wellbeing resources to help support our employees during this time.

We have created new education modules for leaders to help support their teams through change, hosted sessions to help equip our people with tools to navigate change, worked collaboratively with our employee assistance programme partner to deepen their support resources including introducing a new product to offer proactive check-ins with a counsellor and offering a broad range of webinars and educational material.

Fostering a high-performance and inclusive culture

We remain focused on building a performance-based organization, that is representative of the world around us and an inclusive culture that creates a sense of belonging where people can perform at their best.

As part of organizational transformation, we have embedded assurance processes within the selection process centred around promoting fairness and inclusivity for all. In addition, we have engaged with our business resource groups, using listening sessions and regular feedback channels to understand concerns and requests for support.

Reward in our new businesses

As we have acquired a number of new businesses – including TravelCenters of America in May 2023 and more recently Lightsource bp and bp bionergy in October 2024 – we have reviewed the reward framework of each new business on an individual basis. As part of these reviews, it is recognized that a universal approach may not meet the unique needs of the business.

As part of this process, consideration is given to the local market and talent pool in which the new business predominately operates. For example, the acquisition of TravelCenters of America fundamentally changed our US footprint. The deal added a network of around 290 retail sites across the US and over 20,000 employees to bp's population. Therefore, when reflecting on our reward offering the focus has been on simplification and aligning incentives with the US retail market.

This differs from the approach taken at bp bioenergy, where the workforce consists of over 8,800 employees and 5,600 contractors across our operated mills in Brazil and the annual reward cycle is based on a March year-end in line with the local crop season.

From a safety perspective, our intention is to embed bp's safety culture, operating systems and practices across all our businesses. We acknowledge this can take time depending on the complexity of the newly acquired business[a].

Workforce engagement

bp places particular importance on engaging with employees, recognizing that it is critical to have an engaged workforce to deliver our strategy.

We aim to have an open dialogue between the board, senior management and the wider workforce and encourage employees to share their views. For example, employees are kept regularly informed of matters of interest to them through bp's intranet, social media channels, town halls, site visits and webinars.

During 2024, we continued to actively seek employee views through a variety of discussion groups. We held a number of employee-led forums and consulted our business resource groups, with a board-led session as part of the workforce engagement programme (WFEP) in May 2024 (see right).

More detail on bp's WFEP can be found on **page 78**.

Employees at our Cherry Point refinery, US

> "We have worked to develop a bp where our people can be themselves and work in a company that cares while also delivering results..."

Shareholder views

We are committed to ongoing engagement with our shareholders. We believe it is important to meet regularly to understand their views on our remuneration arrangements and their evolving expectations.

Feedback received frames our decisions on executive pay and other topics.

bp.com/reportingcentre

Oak Tree retail site, Surrey, UK

Employee forum

In May 2024 we held a WFEP session with selected employees from different locations across the globe.

The session was led by Dame Amanda Blanc, senior independent director, and Kerry Dryburgh, EVP people, culture & communications.

The focus of the session was on performance, reward and employee engagement, with employees taking the opportunity to share their personal views and experiences of working at bp.

In the session, individuals commented on the strong sense of culture at bp, referencing how our values are clearly present in day-to-day activities. The recent changes to reward, such as the introduction of a bonus uplift relating to individual performance, were also well received and considered motivational.

Key themes of the session were shared with the committee and have provided valuable insight.

a For recently acquired businesses, there is typically a transition period while bp's operating standards, as set out in our Operating Management System★, are integrated or aligned.

Executive directors' pay for 2024

Single figure table – executive directors (audited)[a]

	Murray Auchincloss[b] thousand 2024	Kate Thomson[c] thousand 2024	Murray Auchincloss[b] thousand 2023
Salary	**£1,450**	**£731**	£1,015
Benefits	**£132**	**£67**	£338
Cash allowance in lieu of pension	**£290**	**£146**	£190
Annual bonus[d]	**£734**	**£370**	£1,839
Performance shares[e,f]	**£2,750**	**£575**	£4,362
Total remuneration	**£5,356**	**£1,889**	£7,744
Total fixed remuneration	**£1,872**	**£944**	£1,543
Total variable remuneration	**£3,484**	**£945**	£6,201

a Due to rounding, the totals may not agree exactly with the sum of the component parts.
b Murray Auchincloss was appointed interim CEO on 12 September 2023, having previously been CFO. He was appointed as the permanent CEO on 17 January 2024.
c Kate Thomson was appointed as permanent CFO and joined the board effective from 2 February 2024. The amounts disclosed reflect her service in the year as an executive director.
d In line with the 2023 policy, annual bonus is subject to deferral into shares for three years at a rate of 33% or 50%, depending on whether an individual has met their minimum shareholding requirement. See page 97 for further detail on the approach taken for the 2024 annual bonus.
e For Murray Auchincloss, the value of the performance share award has been calculated using the average share price in the last three months of 2024 of £3.90 and includes notional dividends accrued up to 14 February 2025. For 2023, the performance shares have been restated to reflect the share price on the date of vesting of £4.52 and actual dividends received.
f For Kate Thomson, the value of the performance share award relates to her previous role prior to her appointment to the board, but has been included in the table above for transparency. The award has been calculated using the average share price in the last three months of 2024 of £3.90 and includes notional dividends up to 14 February 2025. For 2022-24, performance share awards below board had a different scorecard to executive directors, which resulted in an outcome of 73% of maximum.

Overview of single figure outcomes

Salary

On 12 September 2023, Murray Auchincloss was appointed as CEO on an interim basis and his base pay was set at £1.45 million. This remained unchanged upon appointment to CEO on 17 January 2024. Kate Thomson was appointed CFO on 2 February 2024 and her base pay was set at £800,000.

Given their recent appointments, neither executive director received an increase in respect of 2024 as part of the annual salary review.

Benefits

Executive directors received car-related benefits, coverage of tax return preparation, security assistance, insurance and medical cover.

Murray Auchincloss's taxable benefits materially decreased year-on-year due to the phasing out of transitional car-related benefits as reported in the 2023 directors' remuneration report.

Cash allowance in lieu of pension

In line with the 2023 directors' remuneration policy, executive directors receive a cash allowance in lieu of pension of 20% of salary. This is in line with the wider workforce in the UK.

Annual bonus

For 2024, the committee assessed performance against a bonus scorecard of measures across three categories: safety and sustainability, operations and financials. These measures were aligned with our strategy and investor proposition as set out at the beginning of the year.

2024 annual bonus scorecard and outcome

Safety and sustainability		Operations		Financials		Formulaic score
22.5%	+	0%	+	0%	=	22.5% out of 100%

Categories	Measures	Threshold (0%)	Target (50%)	Maximum (100%)	Actual	Weight	Outcome
Safety and sustainability (30% weight)	Tier 1 process safety events★	14	9	5	**Actual: 3**	7.5%	7.5%
	Tier 2 process safety events★	39	33	26	**Actual: 35**	7.5%	2.5%
	Operated carbon emissions ($MtCO_2e$)	38.2	35.5	32.8	**Actual: 33.7**[a]	15%	12.5%
Operations (20% weight)	bp-operated reliability★ and availability★	95.1%	95.9%	96.7%	**Actual: 94.7%**	10%	0%
	Transition growth★ engine adjusted EBITDA % growth (vs. 2023)	50%	100%	150%	**Actual: Below threshold**	10%	0%
Financials (50% weight)	Modified free cash flow★ ($bn)	13.2	14.7	16.2	**Actual: 12.5**	25%	0%
	Adjusted EBITDA★ ($bn)	39.4	40.9	42.4	**Actual: 38.0**	25%	0%
	Formulaic outcome (out of 100%)						**22.5%**

Formulaic scorecard outcome	Application of framework on fatalities	Remuneration committee judgement	
22.5% out of 100%	**No reduction** (see **page 98**)	**No adjustment**	**22.5% out of 100%**

a Operated carbon emissions for bonus calculation purposes ($33.7MtCO_2e$) slightly differs from the figure reported elsewhere in the *bp Annual Report and Form 20-F 2024* ($33.6MtCO_2e$) due to the timing of the committee's bonus outcome decision.

Summary of performance

Safety performance, as measured by tier 1 and 2 process safety events★, was strong with a mechanical outcome achieving between target and maximum performance. The number of tier 1 events is less than the prior year, with 3 events in total for 2024 (9 in 2023). This is our lowest recorded number on record and continues the downward trend seen in recent years. For tier 2 events, there was an increase compared to the same period last year, with 35 events in total for 2024 (30 in 2023).

Sustainability performance was previously assessed against sustainable emissions reductions (SER). bp transitioned to use operated carbon emissions from 2024, as it is a more holistic and inclusive measure that represents the full breadth of possible operational movements and is better suited to driving ownership and delivery across the business.

For 2024, operated carbon emissions of 33.7MtCO_2e achieved an outcome between target and maximum and is reflective of our strong progress against net zero operations milestones. The most significant reductions in the year came from flaring reductions and increased reliability in the Azerbaijan, Georgia and Türkiye region and efficient project start-ups.

Emission reduction projects totalling 0.42MtCO_2e implemented by our business in 2024 included: our Gelsenkirchen refinery replaced imported steam from a coal-fired power plant with steam produced in our own gas-fired boilers; bpx energy's central distribution projects, Karnes and Bingo, which enabled decommissioning of legacy natural gas-driven equipment; and restoration of cooling water infrastructure at Cherry Point to reliably meet refinery needs and improve the efficiency of compressor operations.

Further detail on safety and sustainability performance over the year is provided in the safety and sustainability committee (S&SC) report on **page 80**.

Reliability and availability is a combined measure of bp-operated refining availability★ and bp-operated plant reliability★ with a performance outcome of 94.7% – achieving a nil outcome. Plant reliability strengthened year-on-year to 95.2% (95.0% in 2023). However, refining availability was impacted by the Whiting power outage in Q1 2024 and was below threshold at 94.3%.

Transition growth★ engine adjusted EBITDA★ (% growth) was introduced as a more holistic measure focused on transition growth engine financial delivery over the year. The measure is assessed based on annual growth against a 2023 baseline and has achieved a nil vesting outcome. This was primarily driven by lower than expected delivery in bioenergy, convenience and power trading.

Financial performance, as measured by **modified free cash flow★ and adjusted EBITDA**, was below target. bp generated modified free cash flow of $12.5 billion and adjusted EBITDA of $38.0 billion, which resulted in a nil outcome for both measures. Our targets are environment-adjusted at year-end and the revised targets for modified free cash flow and adjusted EBITDA were $14.7 billion and $40.9 billion respectively.

Overall outcome

The formulaic score for the 2024 annual bonus was 22.5% of maximum.

The committee considered bp's framework on fatalities when reflecting on the formulaic outcome. Sadly, there was one fatality during the year within our recently acquired biofuels business. Full details on the application of the framework have been provided on **page 98**.

Having considered the above, alongside a holistic review of performance, the committee determined that no discretion would be applied to the formulaic outcome for executive directors.

Approach to deferral

In relation to the policy on deferral requirements, the committee reviewed the executive directors' shareholding during the year to assess if the minimum shareholding requirement had been met.

As at 14 February 2025, the CEO's shareholding represented 6.1x salary. This is above the minimum shareholding requirement for the CEO of 5x salary and his 2024 award will therefore be subject to a deferral rate of 33%. While the CFO has made strong progress towards her minimum shareholding requirement since her appointment last year, her shareholding represented 2.6x salary on 14 February 2025. This is below her requirement of 4.5x of salary and her 2024 award will therefore be subject to a deferral rate of 50%.

bp's framework on fatalities

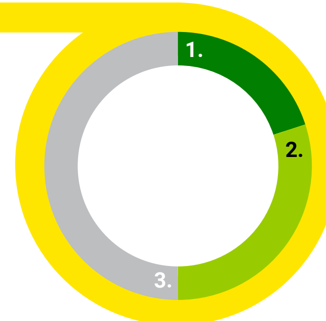
We are working towards our goal of eliminating workplace fatalities. We have implemented a new framework on fatalities. This framework, developed in consultation with shareholders and the safety and sustainability committee, links safety performance directly to the bonus scorecard.

Full details of our framework on fatalities can be found in the 2023 directors' remuneration report.

bp.com/investors

Framework on fatalities

- 1. Operations (20%)
- 2. Safety and sustainability (30%)
- 3. Financial (50%)



Safety and sustainability committee

Influence + Foreseen + Nature of deficiency

Remuneration committee

Collective responsibility + Meaningful adjustment + Judgement within a frame

Treatment of new assets

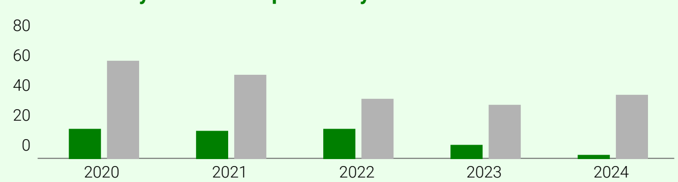
What happened during the year?

Our goal is eliminating fatalities, life-changing injuries and tier 1 process safety events.

Safety performance in 2024

During the year, we made good progress in reducing the number of tier 1 events with our lowest recorded number on record – continuing the downward trend we have seen in recent years. For tier 2 events, there was an increase compared to 2023.

Process safety events over past five years



Tier 1 process safety events · Tier 2 process safety events

This result is reflective of our efforts to improve process safety at bp.

However, this positive performance was overshadowed by the sad news of a fatality in our newly acquired biofuels business (acquired on 1 October 2024) during the year. The incident occurred in mid-October 2024 in Brazil during maintenance activities. While there were no other fatalities during 2024, there were four life-changing injuries. We are taking action to learn from these incidents to help us make further improvements from a personal safety perspective.

How was the framework applied?

The committee consulted the framework in determining the impact of the individual fatality on the 2024 bonus outcome.

Treatment of new assets

The framework allows for major acquisitions to be excluded for an initial period to enable the embedding of bp's safety culture, operating systems and practices.

While a fatality in an excluded new asset will not impact the group bonus score during this transition period, there will be consideration of safety performance within this business during the year – with any adjustments being made locally.

Biofuels incident

In September 2024, prior to the completion of the acquisition, the committee determined that the biofuels business should be excluded for three bonus performance years (i.e. up to the 2026 performance year) for bp employees. This is reflective of the complexity of the business, with over 8,800 employees and 5,600 contractors operating in 11 mills across Brazil.

The acquisition completed on 1 October 2024. From this date, bp had direct operational accountability and was able to start the process of onboarding our Operating Management System (OMS)★. The fatality occurred mid-October and therefore within the exclusion period for the group scorecard.

What was the outcome?

In line with our framework, the committee determined that applying a discretionary adjustment to the formulaic outcome on group-wide bp staff for the fatality in the newly acquired biofuels business would not be appropriate. The incident is, however, expected to have a material impact on local bonus outcomes – with final determinations being made after the business' year-end in March.

No adjustment

resulting in a final bonus score of 22.5% for executive directors.

2022-24 performance share plan scorecard and outcome

2022-24 performance shares were granted under the executive directors' incentive plan (EDIP). The scorecard for this cycle consists of relative total shareholder return (rTSR) (20% weighting), return on average capital employed (ROACE★) (20% weighting), adjusted EBIDA per share CAGR★ (20% weighting) and strategic progress (40% weighting).

2022-24 performance share plan scorecard (audited)

rTSR	+	ROACE	+	Adjusted EBIDA per share CAGR	+	Strategic progress	=	Formulaic score
0%		20%		20%		26.5%		66.5% out of 100%

Categories	Measures	Threshold performance	Maximum performance	Weight	Outcome
rTSR (20% weight)	rTSR	Fourth	First **Actual: Sixth**	20%	0%
Financials (40% weight)	ROACE (average 2022-24)	13.7%	14.7% **Actual: 20.9%**	20%	20%
	Adjusted EBIDA per share CAGR	7.7%	9.7% **Actual: 11.1%**	20%	20%
Strategic progress (40% weight)	Deliver value through resilient hydrocarbon business	Qualitative and quantitative assessment by the committee, see **pages 100-101.**		40%	26.5%
	Demonstrate track record, scale and value in low carbon energy				
	Accelerate growth in convenience and mobility				
	Formulaic outcome (out of 100%)				**66.5%**

Formulaic vesting	Underpin	Final vesting after committee judgement
66.5% out of 100%	Underpin: Committee review of absolute shareholder returns, long-term safety and environmental performance, low carbon and climate change considerations. **No adjustment**	**66.5% out of 100%**

Relative TSR

During the performance period, bp's rTSR performance placed it sixth out of eight in the comparator group which resulted in nil vesting.

Financials

Performance for ROACE and adjusted EBIDA per share CAGR were both strong, at 20.9% and 11.1% respectively over the period, and resulted in maximum vesting of these measures.

As part of the review of outcomes, the committee considers the impact of the external environment with respect to ROACE outcomes, and in respect of adjusted EBIDA per share CAGR the committee reviews share buyback activity outside of plan during the performance period. It determined that, in line with past practice, no further adjustments should be made to either of these elements for the 2022-24 cycle.

★ See glossary on **page 351**

Strategic progress

Overview of strategic progress (2022-24)

Performance of this measure has been challenging to assess as it spans a three-year period that has seen significant change. Our strategy has continued to evolve and update and the criteria we set back at the start of the performance period (2022) to judge progress do not fully reflect current expectations. Alongside assessment against three key pillars (established in 2022), the committee have also taken a broader review of the shareholder experience over the performance period. Further, there has been consideration of mid-cycle changes we have experienced during the performance period, such as bp's updated transition strategy in February 2023 and the key strategic initiatives during 2024 which have laid our foundation for growth. In summary:

- **Resilient hydrocarbons:** Performed well across the board, with strong production delivery, plant reliability★ and unit costs. This was offset by operational challenges during the period which primarily impacted refining availability★. Ultimately, financial performance was strong against this pillar.
- **Low carbon energy:** Progress was mixed with a number of key initiatives completed as management adapted to our evolving strategy and tough market conditions.
- **Convenience and mobility:** bp performed well across our suite of volume measures, but a very challenging market meant financial delivery was lower than expected.

Overall performance: During the period, bp has achieved a number of strategic milestones – particularly in the last year of the performance period – and is well positioned to drive future growth.

1. Deliver value through a resilient hydrocarbon business KPIs (as set in 2022)

Unit production cost On track

Unit production costs remain on track against 2025 target of $6.00/boe, with an average of $6.01/boe over the three-year period.

2022	2023	2024	2025 target
$6.1/boe	$5.8/boe	$6.2/boe	**$6.0/boe**

Plant reliability On track

Average delivery over performance on track to meet the 2025 target of 96.0%. Focus remains on production management and delivering higher reliability targets.

2022	2023	2024	2025 target
96.0%	95.0%	95.2%	**96.0%**

Refining availability Improvement required

For 2024, performance was affected by the plant-wide power outage at Whiting. Excluding this event would have meant we were on track to reach target.

2022	2023	2024	2025 target
94.5%	96.1%	94.3%	**96.0%**

Overview

- Continued high grading of portfolio to drive higher margins. Completed joint venture conversions in Angola and Iraq, extended Indonesia production-sharing contract, completed 10 major projects and increased bpx production by 33%.
- Production on track with 2024 progress broadly on plan. 2022 and 2023 production were +2% vs. plan.
- The hydrocarbon business performed well against adjusted EBITDA and free cash flow measures – with actual performance ahead of expectations for both measures.

2. Demonstrate track record, scale and value in low carbon energy KPIs (as set in 2022)

Developed renewables to FID★ Improvement required

To the end of 2024, bp has delivered 8.2GW to FID (bp net). The main contributions have come from Lightsource bp and the 100% bp solar pipeline (Cygnus). The solar sector has been significantly impacted by increased interest rates, inflation and supply issues. Offshore wind has been materially impacted by supply chain inflation across all sub-sectors including turbines and vessels.

While good progress has been made, 2025 targets were challenging and performance under this measure is tracking behind expectations.

2022	2023	2024	2025 target
5.8GW	6.2GW	8.2GW	**20GW**

Renewables pipeline★ Strong progress

Over the three-year period, there has been substantial growth in our renewables pipeline. This has largely been driven by Lightsource bp and success in our bids within offshore wind.

In hydrogen, projects portfolio has been prioritised based on returns and feasibility, with the business achieving four recent FIDs.

2022	2023	2024
37.2GW	58.3GW	60.6GW

Overview

- The low carbon energy pillar has materially transformed since the setting of targets in 2022. From a period of volume-driven origination, bp has moved into a stage of consolidation, portfolio reset and focus across all businesses within a more constrained capital frame.
- Low carbon energy delivered lower adjusted EBITDA than expected over the period. This was attributable to the challenging solar market in the US in 2023 and rapid ramp-up in hydrogen and offshore wind.

3. Accelerate growth in convenience and mobility KPIs (as set in 2022)

Convenience margin growth★ On track

In 2023, the acquisition of TravelCenters of America was completed. This is expected to substantially grow bp's global convenience gross margin★ in coming years and bring growth opportunities – as seen by strong performance in 2024 (17% vs. 2025 target of 10%).

2022	2023[a]	2024	2025 target[a]
9%	9%	17%	**10%**

Strategic convenience sites★ Ahead

We remain on track to meet our 2025 target of 3,000 sites. This has been supported by the full ownership of *Thorntons* in 2021 and acquisition of TravelCenters of America.

2022	2023	2024	2025 target
2,400	2,850	2,950	**3,000**

Castrol performance (revenue) On track

Castrol has continued to demonstrate year-on-year earnings and volume growth, as well as completing a number of strategic initiatives, including a new strategic partnership with Audi in Formula 1 and diversifying into battery-swapping ecosystems.

2022	2023	2024	2025 target[b]
$6.9bn	$7.0bn	$6.9bn	**n/a**

Overview

- Performance across the convenience and mobility pillar has been strong versus the targets we set at the beginning of 2022. However, market conditions have been challenging which has impacted financial delivery, leading to mixed performance.
- During the period, financial performance was impacted by cost inflation, challenging market environments and prolonged impact of COVID-19 on businesses such as *Castrol*.

a 2023 excludes the acquisition of TravelCenters of America. The 2025 target represents the wider aim of achieving ~10% CAGR by 2030 (as set in 2023).
b The *Castrol* performance KPI was retired during the performance period and performance has therefore been considered 'in the round' including reference to earnings and volume growth.

Overall assessment

In progressing our strategic agenda, we have not only reviewed performance against the three strategic pillars of our previous strategy but also key strategic highlights, many of which culminated in the last year of the performance period, including:

Low carbon energy

- Completed transactions for 100% ownership of bp Bunge Bioenergia and Lightsource bp.
- New joint ventures including JERA Nex bp with JERA Co., Inc.

Resilient hydrocarbons

- Sanctioning 10 higher value major projects – including Kaskida and Tangguh UCC.
- Agreeing new access to resources in regions we know well, like the Middle East and India, where we are now technical services providers for the country's largest offshore oil and gas field.
- Gas is now flowing at our Greater Tortue Ahmeyim (GTA) project off the coast of West Africa. Once fully commissioned, it is set to produce 2.4 million tonnes of LNG annually.

Convenience and mobility

- In 2024, *Castrol* grew underlying earnings by 14% and has demonstrated six consecutive quarters of year-on-year underlying earnings growth.

Financial

- Delivery of structural cost reductions of around $0.8 billion in 2024. This more than offsets significant increases from inflation, foreign exchange and costs associated with growing the business. Overall, we reduced our underlying operating expenditure by $300 million towards our target of $4-5 billion of structural cost reductions by end-2027.

Resulting score

Accounting for delivery (volume and value), bp's evolving strategic context and the above strategic milestones, the committee determined performance against this measure should result in 66% of maximum vesting (2021-23: 75% of maximum).

Strategic progress remains a key component of our long-term scorecard for outstanding awards and the committee will continue to apply judgement within the context of broader strategic delivery.

Other vesting considerations

Along with the results from the scorecard measures, the committee considers an 'underpin' to the formulaic outcome in order to determine the final vesting percentage. The underpin broadens our performance assessment, allowing us to consider vesting outcomes with overall alignment to absolute shareholder returns, environmental and safety factors and progress in matters relating to low carbon and climate change. Where relevant, we take input from the safety and sustainability committee and the audit committee to deepen and enhance our perspective.

Having considered the above, the committee concluded that the vesting outcome was suitably reflective of the company's underlying performance and the experience of shareholders overall. The committee agreed it was not necessary to apply discretion to the formulaic outcome and approved vesting of 66.5% for the 2022-24 EDIP award. This decision yields the outcome shown in the table below for the CEO. The scorecard detail is shown on **page 99**.

2022-24 performance share plan outcome (audited)

	Shares awarded	Unvested shares following application of performance factor	Value of unvested shares following application of performance factor	Impact of share price change[a]
Murray Auchincloss	937,500	704,790	£2,749,950	£-317,649
Kate Thomson[b]	89,300	147,391	£575,090	£15,815

a These values reflect the impact of the change in share price since grant related to the number of shares which are no longer subject to performance conditions, including dividend equivalents accrued at 14 February 2025. The face values of these awards were calculated using a market price of ordinary shares at close on the dates of award, as follows: £4.35 on 26 May 2022 and £3.79 on 17 June 2022 respectively. The average share price during Q4 2024 was £3.90. The amount reported as 2024 income in the single figure is therefore £2.750 million for Murray and £0.575 million for Kate.
b Kate Thomson's award was made under the below board performance share plan where grants are made at 50% of maximum, rather than at 100% of maximum as for the EDIP. For 2022-24, performance share awards below board had a different scorecard to executive directors, which resulted in an outcome of 73% of maximum.

Policy implementation for 2025

The current remuneration policy was approved by shareholders at the 2023 annual general meeting on 27 April 2023. The full policy is displayed on the company's website at **bp.com/remuneration**. The table below shows how the remuneration policy will be implemented in 2025, alongside a summary of key features.

Element	Policy feature	2025 implementation
Salary	To provide fixed remuneration to reflect the scale and complexity of both the business and the role, and to be competitive with the external market. When setting salaries, the committee considers practice in other energy majors as well as European and US companies of a similar size, geographic spread and business dynamic to bp. Percentage increases for executive directors will not exceed that for the wider workforce, other than in specific circumstances identified by the committee (e.g. in response to a substantial change in responsibilities). Salaries are normally set in the home currency of the executive director and are reviewed annually. They may be reviewed at other times where appropriate.	• Murray Auchincloss's salary will increase by 4%, in line with the wider workforce, to £1,508,000 following the 2025 AGM. • Kate Thomson's salary will increase by 8% to £864,000 following the 2025 AGM. This is to reflect her development in role and leadership for the Finance function since appointment in February 2024. • The budgeted increase to our UK salaried staff effective from 1 April 2025, our annual salary review date, will be 4%.
Pensions and benefits	Executive directors normally participate in the company retirement plans that operate in their home country. New appointees from within the bp group retain previously accrued benefits related to service prior to appointment as executive director. For their service as a director, cash allowance in lieu of pension will be up to 20% of base salary. For future appointments, the committee will carefully review any retirement benefits to be granted to a new director, taking account of retirement policies across the wider group and any arrangements currently in place.	• Murray and Kate's cash allowance in lieu of pension is 20% of base pay (in line with the wider workforce). • Prior to their appointment as executive directors, Murray received a US deferred pension and Kate received a UK deferred pension. No further pension is accrued under either plan. • Benefits will remain unchanged for 2025 and include car-related provisions, security assistance, insurance and medical cover.
Annual bonus	Bonus is measured against an annual scorecard. The committee holds discretion to choose the specific measures and the relative weightings adopted in the annual scorecard, to reflect the annual plan as agreed with the board. Numeric scales are set for each measure, to score outcomes relative to targets. A scorecard outcome of 1.0 reflects the target outcome and 2.0 is the maximum outcome. Target bonus is 112.5% of salary, and maximum bonus is 225% of salary. Half the bonus is paid in cash, and half is deferred into bp shares for three years up until the 'minimum shareholding requirement' is met. At this point, 67% is paid in cash and 33% is paid in bp shares. Dividends (or equivalents, including the value of any reinvestment) may accrue in respect of any deferred shares. Awards are subject to operationally robust and effective malus and clawback provisions as described below.	• For 2025, our scorecard will be assessed against the following categories: safety and sustainability (30%) and financials and operations (70%). • We intend to make the following changes to performance measures for 2025: – Introduce a structural cost reduction measure that is aligned with our forward-looking commitments. This replaces the earnings measures in the scorecard. – Replace the measure focused on transition growth★ engines with increased weighting on modified free cash flow★ and bp-operated reliability★ and availability★. • See **page 104** for further details on measures for the 2025 annual bonus. • The framework on fatalities, which helps guide decisions on adjustments to the bonus outcome in relation to fatalities, will continue to be applied. Further detail has been provided on **page 98.**

Element	Policy feature	2025 implementation
Performance shares	Performance shares are granted with a three-year performance period, measured against a scorecard. The committee holds discretion to choose the specific measures and the relative weightings adopted in the scorecard, to ensure they are focused on the near-term priorities for delivering the bp strategy in the interests of shareholders. Annual grants are 500% of salary for the CEO, and 450% of salary for any other executive director. Awards will vest in proportion to the outcomes measured through the performance scorecard, subject to any adjustment by the committee, and will be subject to a three-year post-vesting holding period. Awards are subject to operationally robust and effective malus and clawback provisions as described below.	• For our 2025-27 cycle, the scorecard categories will remain unchanged from the 2024-26 cycle and will be assessed against the following: rTSR (25%), financials (40%), environmental, social and governance (15%) and strategic progress (20%). • The only change being made to the chosen performance measures for the 2025-27 cycle is the introduction of an adjusted free cash flow CAGR★ measure. This replaces adjusted EBIDA CAGR per share★. All other measures are to remain the same. • See **page 104** for further details on measures for the 2025-27 EDIP. • The award will continue to be subject to an underpin that takes into consideration in-year safety outcomes and long-term trends in safety outcomes over the performance period. • The 2025-27 awards will be granted based on the average closing share price of each calendar day in the 90-day period ending on the date of bp's 2025 AGM.
Shareholding requirement	CEO to build a shareholding of at least five times salary, and other executive directors four and a half times salary, within five years of appointment. Executive directors are required to maintain that level for at least two years post-employment.	• Murray's shareholding has reached 6.1 times salary, above his minimum shareholding requirement of 5 times of salary. • Kate's shareholding has reached 2.6 times salary. Over the next four years, to 2029, Kate will work towards reaching her minimum shareholding requirement of 4.5 times of salary.
Malus and clawback	Operationally robust and effective malus and clawback provisions apply to our incentive awards. Malus provisions may be applied where there is: a material safety or environmental failure; an incorrect award outcome due to miscalculation or incorrect information; a restatement due to financial reporting failure or misstatement of audited results; material misconduct; or other exceptional circumstances that the committee considers similar in nature. Clawback provisions may apply where there is: an incorrect outcome due to miscalculation or incorrect information; a restatement due to financial reporting failure or misstatement of audited results; or material misconduct.	
Committee flexibility	The committee has discretion to adjust performance measures and weightings, and to revise the peer group for the rTSR measure. This discretion allows appropriate realignment, throughout the policy term, for changes in the annual plan and for the anticipated evolution of the low carbon business environment. The committee also holds discretion in determining the outcomes for annual bonus and performance shares, allowing them to take broad views on alignment with shareholder experience, environmental, societal and other relevant considerations e.g. portfolio changes.	

★ See glossary on **page 351**

Measures for the 2025 annual bonus

Provided below is a summary of the performance measures we have chosen for the 2025 annual bonus plan scorecard. The targets are commercially sensitive and will be disclosed in the 2025 directors' remuneration report.

We are replacing our earnings (adjusted EBITDA★) measure with structural cost reductions★ to better align with the financial priorities set out in the Capital Markets Update announcement in February 2025. This measure will be assessed against a 2023 baseline and is positioned to capture sustainable cost reductions that can be maintained beyond 2027.

In line with our reset strategy, the measure on transition growth★ engines has been removed from the scorecard for 2025. In the interest of simplification, the committee determined that the scorecard should be kept to five measures. The weighting of modified free cash flow★ and bp-operated reliability★ and availability★ will be increased – from 25% to 30% and 10% to 15% respectively. This change mirrors our focus on cash generation and driving strong operations for 2025.

Importantly, the framework on fatalities will continue to apply to the 2025 annual bonus and will be considered at year-end if a fatality occurs during the year. See **page 98** for further detail on its application in 2024.

Safety and sustainability

30%

Measures include	Weighting
Tier 1 and tier 2 process safety events★ (measured separately)	15%
Operated carbon emissions	15%

Financials and operations

70%

Measures include	Weighting
Modified free cash flow	30%
Structural cost reduction	25%
bp-operated reliability and availability	15%

Measures for the 2025-27 performance shares (EDIP)

Provided below is a summary of the measures we have chosen for the 2025-27 performance share plan. The four categories remain unchanged from the prior year and there has been no change to respective weightings.

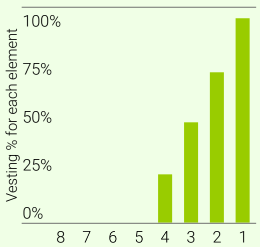
Under our financials category, we are proposing to introduce an adjusted free cash flow CAGR measure (20% weight) and to modify the ROACE measure to align with our strategic commitments. The committee reflected on the dual focus of free cash flow in the short and long-term incentive scorecards and determined it was appropriate given our strategic focus on cash generation – with adjusted free cash flow being a primary target in bp's reset strategy. The two cash measures; modified free cash flow and adjusted free cash flow CAGR are different, with the former covering a holistic view of in-year cash generation (including working capital and proceeds) and the latter representing underlying free cash flow growth, removing more volatile items, in line with our external targets. The ROACE measure now fully aligns with our external targets with measurement at the end of 2027.

For strategic progress, the measure will remain subject to the committee's judgement at the end of the three-year period. The judgement of performance will take into account progress against the financial targets set under our reset strategy – including reference to measures such as divestments, net debt★ and structural cost reductions. This will be alongside our holistic review of progress against our strategy, to ensure that outcomes are aligned with the shareholder experience.

rTSR

25%

Peer group of seven companies: Chevron, Eni, Equinor, ExxonMobil, Repsol, Shell and TotalEnergies (and bp)[a]

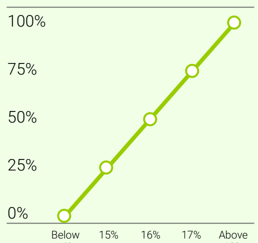


rTSR ranking

Financials

20%

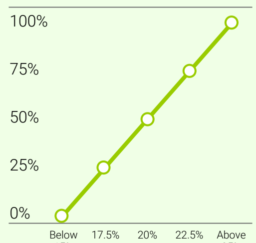
ROACE[b]★



ROACE

20%

Adjusted free cash flow CAGR[c]

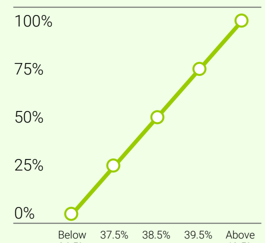


Adjusted free cash flow CAGR

Environmental, social and governance

15%

Cumulative reduction % in operated carbon emissions[d]



Cumulative reduction % in operated carbon emissions

Strategic progress

20%

Holistic review of progress against strategy set out in the Capital Markets Update in February 2025.

Subject to the remuneration committee's judgement.

Consideration may be given to the following measures:

- Divestments
- Net debt
- Structural cost reduction

- Underpin will take into account safety outcomes prior to determining final vesting percentage.
- Remuneration committee discretion will reflect shareholder experience, environment, societal and other inputs.
- Robust malus and clawback may apply in certain circumstances.

a Nil vesting for fifth place or lower.
b Based on ROACE at the end of the three-year period. Targets will be adjusted for the environment.
c Annualised growth rate of adjusted free cash flow vs. 2024 baseline. Targets will be adjusted for the environment.
d Scope 1 and 2 GHG emission reductions vs. 2019 baseline from operated carbon emissions including portfolio change.

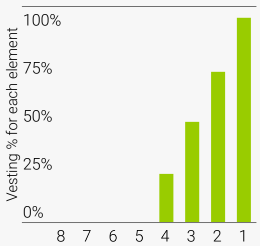
Provided below is an overview of the performance measures and weightings of each of our in-flight awards.

Measures for 2023-25 performance shares

rTSR

20%

Peer group of seven companies: Chevron, Eni, Equinor, ExxonMobil, Repsol, Shell and TotalEnergies (and bp)

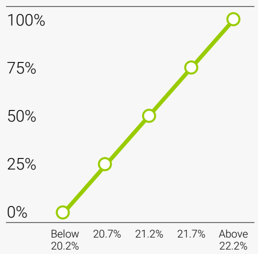


rTSR ranking

Financials

20%

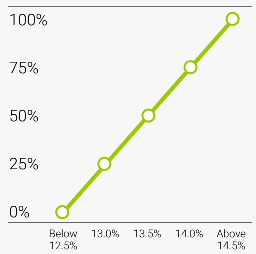
ROACE (average 2023-25)



ROACE

20%

Adjusted EBIDA per share CAGR

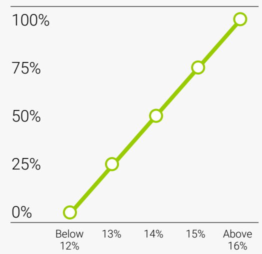


Adjusted EBIDA per share CAGR

Environmental, social and governance

15%

Net zero across entire bp operations by 2050 (Scope 1 + 2)



Net zero

Strategic progress[a]

25%

Weighting of measures subject to remuneration committee judgement:

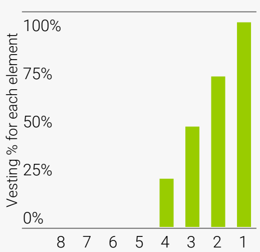
- Deliver value through a resilient hydrocarbon business.
- Demonstrate track record, scale and value in low carbon energy.
- Accelerate growth in convenience and mobility.

Measures for 2024-26 performance shares

rTSR

25%

Peer group of seven companies: Chevron, Eni, Equinor, ExxonMobil, Repsol, Shell and TotalEnergies (and bp)

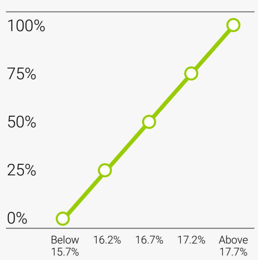


rTSR ranking

Financials

20%

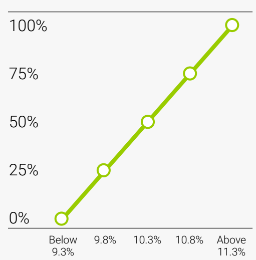
ROACE (average 2024-26)



ROACE

20%

Adjusted EBIDA per share CAGR

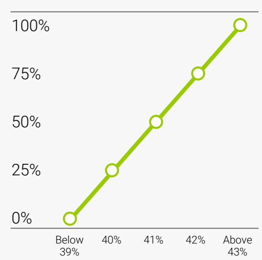


Adjusted EBIDA per share CAGR

Environmental, social and governance

15%

Cumulative reduction % in operated carbon emissions



Cumulative reduction % in operated carbon emissions

Strategic progress

20%

Subject to remuneration committee judgement.

Following the Capital Markets Update in February 2025, judgement of strategic progress will adopt the same frame as set out for the 2025-27 cycle.

a Performance against the three pillars will be reviewed and scored in the context of the strategic changes announced in 2023 and the Capital Markets Update in February 2025.

★ See glossary on **page 351**

Directors’ remuneration report continued

Stewardship and executive director interests

We believe that our executive directors should build and maintain a material interest in the company. Our policy therefore requires the CEO and CFO to build a personal shareholding of five times and four and a half times, respectively, their salary within five years of their appointment. They are expected to maintain this level of personal shareholdings for two years post-employment.

Directors’ shareholdings and aggregated interests (audited)

The table below details the personal shareholdings of each executive director. These figures include all beneficial and non-beneficial ownership of shares of bp (or calculated equivalents) that have been disclosed to the company. Murray Auchincloss has met the minimum shareholding requirement (MSR) under the policy. Kate Thomson is expected to satisfy the policy requirement that applies five years from her date of appointment, 2 February 2024. The committee has reviewed and confirmed this position and will continue to monitor compliance with this policy.

	Directors' ordinary shares or equivalents at 14 Feb 2025	Aggregated interests at 14 Feb 2025, all plans: Unvested awards not subject to performance conditions		Unvested awards subject to performance conditions		Current shareholding for MSR[b]	Value of current shareholding[c], £	Multiple of salary achieved
		Shares[a]	Options	Shares	Options			
Murray Auchincloss[d]	1,319,688	1,387,250	152,301	2,200,575	—	1,888,476	8,838,068	6.1
Kate Thomson	230,357	350,322	500,000	808,846	—	437,799	2,048,899	2.6

a Includes deferred and restricted shares, and performance shares prior to application of the performance factor.
b Includes ordinary shares or equivalents and unvested awards not subject to performance conditions on a net-of-tax basis, excluding dividends.
c Based on ordinary share price at 14 February 2025 of £4.68.
d Includes interests of a person closely associated with Murray Auchincloss.

Executive directors have additional interests in performance and deferred bonus shares. These interests are shown in aggregate in the table above, and interests awarded during 2024 in the tables below. For performance shares, the figures reflect maximum possible vesting levels (excluding the addition of reinvested dividends) even though the actual number of shares that vest will depend on the extent to which performance conditions are satisfied.

Performance and deferred shares (audited)

	Award	Number of shares granted	Grant date	Face value of the award[a], £	Vesting date
Murray Auchincloss	2024-26 EDIP Performance[b]	1,482,617	7 May 2024	7,472,390	May 2027
Kate Thomson	2024-26 EDIP Performance[b]	736,196	7 May 2024	3,710,428	May 2027
Murray Auchincloss	2024 EDIP Deferred[c]	124,128	7 May 2024	625,605	May 2027

a The face value of awards granted during 2024 have been calculated using a market price of ordinary shares at close on the date of award, as follows: £5.04 on 7 May 2024. In calculating the number of ordinary shares over which these awards were made, the committee applied the average price of ordinary shares over the 90 calendar days up to and including the annual general meeting that was held on 25 April 2024 (£4.89).
b Performance conditions are measured 15% on cumulative reduction % in operated carbon emissions, 25% on TSR relative to Chevron, ExxonMobil, Shell, TotalEnergies, Eni, Equinor and Repsol over three years, 20% ROACE averaged over the performance period, 20% adjusted EBIDA per share CAGR measured vs. year ended June 2020 and 20% strategic progress assessed over the performance period. Minimum vesting under this award (below threshold performance) is 0%. At threshold performance, vesting would be 6.25% of maximum.
Since 2010, vesting of the performance shares under EDIP has been subject to a safety underpin. If the committee assesses that there has been a material deterioration in safety performance, or there have been major incidents, either of which reveal underlying weaknesses in safety management, then it may conclude that shares should vest only in part, or not at all. In reaching its conclusion, the committee obtains advice from the S&SC.
The performance period is 1 January 2024 to 31 December 2026.
The 2025 performance share awards under EDIP are expected to be made following the conclusion of the 2025 annual general meeting.
c There is no identified minimum vesting threshold level. The 2024 bonus year deferred share awards under EDIP are expected to be made following the conclusion of the 2025 annual general meeting.

Directors and leadership team

No directors or other leadership team members own more than 1% of the shares in issue. At 14 February 2025, our directors and leadership team members collectively held interests of 6,288,180 ordinary shares or their calculated equivalents, 4,339,104 restricted share units (with or without conditions) or their calculated equivalents, 7,399,346 performance shares or their calculated equivalents and 6,174,714 options over ordinary shares or their calculated equivalents, under bp group share option schemes.

Chair and non-executive director outcomes and interests

Fee structure

The table below shows the fee structure for the chair and non-executive directors (NEDs). The chair is not eligible for committee chairship and membership fees. The senior independent director (SID) is eligible for committee chairship and membership fees, and their fee includes the board member fee. Committee chairs do not receive a membership fee for the committee they chair.

Under the 2023 policy, fee levels are reviewed annually alongside wider workforce salaries and any changes are put into effect from 1 April. Taking all factors into consideration, for 2025 the board agreed to implement a 4% increase to the base fee for NEDs and for the SID, aligned with the salary increase budget for the UK wider workforce. Determination of the fees payable to the chair falls to the remuneration committee, which agreed to align the percentage increase of the chair's fee with the other NEDs. Following board and remuneration committee approval, the remuneration arrangements for the chair and NEDs will be adjusted with effect from 1 April 2025.

£ thousand per annum	2025/26 fees	2024/25 fees
Chair	**888**	854
Senior independent director	**181.5**	174.5
Board member	**130.5**	125.5
Audit, remuneration and safety and sustainability committees chairship	**35**	35
Committee membership	**20**	20

2024 remuneration (audited)

The table below shows the fees paid and applicable benefits. Benefits include travel and other expenses relating to the attendance at board and other meetings. Under the terms of his engagement with the company, Helge Lund has the use of a fully maintained office for company business, a car and driver, and security advice in London. Benefits values have been grossed up using a tax rate of 45%, where relevant, as an estimation of tax due.

	Fees		Benefits		Total	
£ thousand	2024	2023	2024	2023	2024	2023
Dame Amanda Blanc	**198**	159	**1**	2	**198**	161
Pamela Daley	**164**	159	**17**	67	**181**	226
Helge Lund (chair)	**845**	809	**38**	66	**882**	875
Melody Meyer[a]	**182**	184	**9**	29	**191**	213
Tushar Morzaria	**189**	174	**1**	3	**190**	177
Hina Nagarajan[b]	**157**	116	**17**	32	**174**	148
Satish Pai[b]	**144**	116	**5**	39	**149**	155
Paula Rosput Reynolds[b]	**72**	220	**6**	20	**78**	240
Karen Richardson[c]	**169**	178	**16**	18	**185**	196
Sir John Sawers[b]	**57**	174	**12**	7	**68**	181
Dr Johannes Teyssen[a]	**160**	149	**5**	15	**165**	164

a Fee includes £10,000 p.a. for being a member of the bp geopolitical advisory council. The fee for this role ceased effective 1 April 2024.
b Hina Nagarajan and Satish Pai were appointed on 1 March 2023. Paula Rosput Reynolds and Sir John Sawers retired on 25 April 2024.
c Fee includes £25,000 p.a. for chairing the bp digital advisory council.

Chair and non-executive directors' interests (audited)

The figures below include all the interests of the chair and each NED of the company in shares of bp (or calculated equivalents) that have been disclosed to bp. Our 2023 policy encourages NEDs to establish a holding in bp shares of the equivalent value of one year's base fee during their tenure.

	Ordinary shares or equivalents[a]					
	At 1 Jan 2024	At 31 Dec 2024	Changes to 14 Feb 2025	At 14 Feb 2025	Value of current shareholding[b]	% of guideline achieved
Dame Amanda Blanc	23,500	23,500	–	23,500	£109,980	88%
Pamela Daley	40,332	40,332	–	40,332	$235,270	147%
Helge Lund (chair)	600,000	600,000	–	600,000	£2,808,000	329%
Melody Meyer	20,646	38,646	–	38,646	$225,435	141%
Tushar Morzaria	71,972	71,972	–	71,972	£336,829	268%
Hina Nagarajan	10,000	25,944	–	25,944	£121,418	97%
Satish Pai	12,000	33,000	–	33,000	$192,500	120%
Paula Rosput Reynolds[c]	78,378	–	–	–	–	–
Karen Richardson	29,316	35,316	–	35,316	$206,010	128%
Sir John Sawers[c]	24,242	–	–	–	–	–
Dr Johannes Teyssen	35,000	35,000	–	35,000	£163,800	131%

a Includes interests of persons closely associated.
b Based on ordinary share and ADS prices at 14 February 2025 of £4.68 and $35.00. Where a US$ value is provided these shares are held as ADSs.
c Paula Rosput Reynolds and Sir John Sawers retired on 25 April 2024.

★ See glossary on **page 351**

Past directors

Payments for loss of office (audited)

No payments were made during the financial year for loss of office, except as already disclosed in the 2023 directors' remuneration report.

Payments to past directors (audited)

No payments were made during the financial year to past directors, except as already disclosed in the 2023 directors' remuneration report.

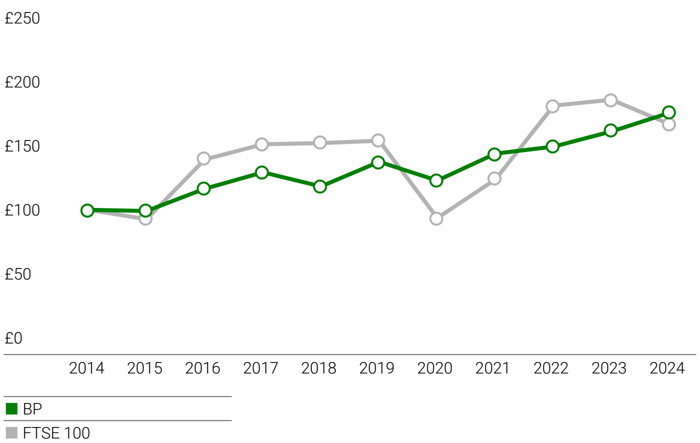
Post-employment benefits (audited)

Bob Dudley and Brian Gilvary were provided with tax return preparation support amounting to £1,779 and £11,455 respectively.

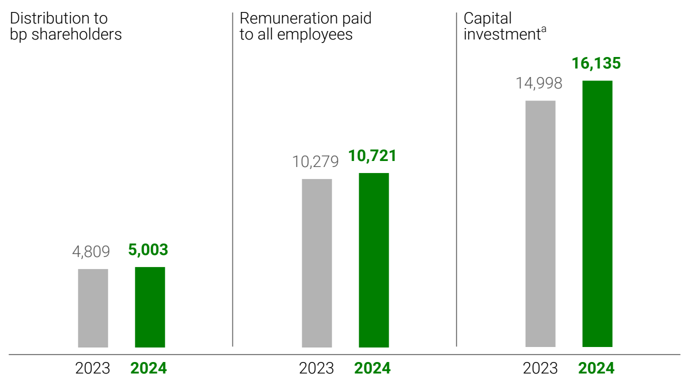
We made no other payments within the scope of the disclosure requirements to any past director of bp during 2024 (we have no de minimis threshold for such disclosures).

Other disclosures

Historical TSR performance



Relative importance of spend on pay ($ million)



a Organic capital expenditure.

The graph above shows the growth in value of hypothetical £100 investments in BP p.l.c. ordinary shares, and in the FTSE 100 index (of which bp is a constituent), over 10 years from 31 December 2014 to 31 December 2024.

History of chief executive officer remuneration

Year	Chief executive officer	Total remuneration, thousand	Annual bonus % of maximum	Performance shares % of maximum
2015	Bob Dudley	$19,376	100	74.3
2016	Bob Dudley	$11,904	61	40
2017	Bob Dudley	$15,108	71.5	70
2018	Bob Dudley	$15,253	40.5	80
2019	Bob Dudley	$13,234	67.5	71.2
2020[a]	Bob Dudley	$188	0	32.5
	Bernard Looney	£1,735	0	32.5
2021	Bernard Looney	£4,457	80.5	30
2022	Bernard Looney	£10,331	75.5	54
2023[a,b]	Bernard Looney	£1,175	n/a	n/a
	Murray Auchincloss	£5,391	79.5	75
2024[c]	**Murray Auchincloss**	**£5,356**	**22.5**	**66.5**

a 2020 and 2023 figures show remuneration for the periods of qualifying service as CEO during the respective years.
b As reported in the 2023 directors' remuneration report, Bernard Looney stepped down as CEO and from the board of directors with immediate effect on 12 September 2023 and was succeeded by Murray Auchincloss as interim CEO on the same date. In respect of 2023, Bernard Looney did not receive any variable pay awards and his single figure shown in the table above excludes the impact of malus and clawback. For Murray Auchincloss, the 2023 figure has been updated based on the actual share price used for vesting of £4.52.
c Share price has been based on the average share price over Q4 of the 2024 FY of £3.90.

Chief executive officer to employee pay ratio

Year	Method	25th percentile: pay ratio, total pay and benefits, (salary)	50th percentile: pay ratio, total pay and benefits, (salary)	75th percentile: pay ratio, total pay and benefits, (salary)
2019[a]	Option A	543:1	188:1	82:1
2020[a]	Option A	99:1	40:1	19:1
2021	Option A	208:1	87:1	35:1
2022	Option A	421:1	172:1	69:1
2023[b]	Option A	268:1	103:1	45:1
2024[c]	**Option A**	**196:1**	**74:1**	**37:1**
		£27,343	**£72,678**	**£143,202**
		(£25,304)	**(£54,106)**	**(£92,900)**

a Bob Dudley's pay has been converted from US dollars as per the ratios reported in the *bp Annual Report and Form 20-F 2020*.
b For 2023, the total single figure used to derive the CEO pay ratio is a combination of the two individuals in position of CEO during the year. In respect of the former CEO, the calculation has been based on the total single figure excluding the impact of malus and clawback in order to provide a comparison with prior years. Appropriate pro-rating of fixed and variable pay has been applied.
c Share price for the CEO share plan vesting has been based on the average share price over Q4 of the 2024 FY of £3.90.

This is our sixth year reporting the CEO pay ratio following the requirements introduced in 2018. As per the past five years, we have selected Option A as our reporting basis, being the most accurate approach available, and we confirm that no broadly applicable components of pay have been omitted. Where necessary, full-time equivalent pay has been calculated by simple engrossment of part-year values. Employee values relate to pay and benefits for the year ended 31 December 2024.

Changes in the pay ratio over time reflect the fact that CEO remuneration is more heavily weighted to variable pay, resulting in larger year-on-year swings than wider workforce pay. This is evidenced by the variability of the CEO pay ratio over the past six years. This volatility in the pay ratio reporting from year to year is expected, and illustrates one of the challenges in commenting on whether the pay differentials are appropriate. In 2024, the 50th percentile pay ratio decreased from 103:1 to 74:1. This was largely driven by the outcomes of the CEO's variable awards, with the lowest bonus outcome in the past 10 years (excluding nil bonus for 2020) and the performance share award being granted at a lower multiple of salary when he was in position as CFO.

The committee believes in performance-based remuneration. For all employees eligible to participate in the annual cash bonus plan, there is an individual uplift available each year which allows managers to nominate individuals based on their personal contributions during the year. For senior leaders, a significant portion of the remuneration package continues to be linked to performance-based reward. It is therefore the view of the committee that the remuneration frameworks we have in place for executive directors and the wider workforce are fit-for-purpose and deliver pay outcomes appropriate to the circumstances of the year, with differentials that reflect the relative contributions made at different levels of the organization.

The committee is satisfied that the median pay ratio reported this year is consistent with bp's pay policies for employees and does not constitute a reason to modify our pay programmes.

Percentage change comparisons: directors' remuneration versus employees

In the table below, values in column 'a' represent the percentage change in salary and fees; values in column 'b' represent the percentage change in taxable benefits; and values in column 'c' represent the percentage change in bonus outcomes for performance periods in respect of each financial year. For the purposes of comparison, the employee percentages shown below represent the relative change between the median full-time equivalent pay for every employee employed at BP p.l.c. at any point during the relevant financial year, and the equivalent median value for the preceding financial year. Where increases are infinite relative to the preceding year, we have shown them as 100% for illustration, where a director was appointed or retired part-way through the year we have annualized pay except for one-time items, and where comparison to the prior year is not possible we have used dashes.

	2024 vs. 2023			2023 vs. 2022			2022 vs. 2021			2021 vs. 2020			2020 vs. 2019		
Percentage change for:	a	b	c	a	b	c	a	b	c	a	b	c	a	b	c
Employees	4%	0%	-65%	6%	1%	4%	2%	1%	45%	7%	-9%	100%	0%	0%	-100%
Murray Auchincloss	43%	-61%	-60%	30%	283%	31%	7%	530%	3%	5%	5%	100%	—	—	—
Kate Thomson	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dame Amanda Blanc	24%	-72%	n/a	38%	100%	n/a	—	—	n/a	—	—	n/a	—	—	n/a
Pamela Daley	3%	-75%	n/a	2%	2%	n/a	7%	43%	n/a	4%	1385%	n/a	-15%	-92%	n/a
Helge Lund (chair)	4%	-43%	n/a	3%	78%	n/a	0%	97%	n/a	0%	-24%	n/a	0%	-74%	n/a
Melody Meyer	-1%	-68%	n/a	2%	-14%	n/a	13%	139%	n/a	-4%	283%	n/a	9%	-77%	n/a
Tushar Morzaria	9%	-73%	n/a	2%	-46%	n/a	25%	100%	n/a	5%	0%	n/a	—	—	n/a
Hina Nagarajan	13%	-46%	n/a	—	—	n/a	—	—	n/a	—	—	n/a	—	—	n/a
Satish Pai	3%	-88%	n/a	—	—	n/a	—	—	n/a	—	—	n/a	—	—	n/a
Paula Rosput Reynolds	3%	-70%	n/a	2%	-14%	n/a	16%	145%	n/a	—	228%	n/a	2%	-92%	n/a
Karen Richardson	-5%	-12%	n/a	11%	-20%	n/a	30%	96%	n/a	—	—	n/a	—	—	n/a
Sir John Sawers	3%	63%	n/a	2%	105%	n/a	17%	1%	n/a	—	1588%	n/a	—	-83%	n/a
Johannes Teyssen	7%	-68%	n/a	3%	12%	n/a	21%	65%	n/a	—	—	n/a	—	—	n/a

Independence and advice

The board considers all committee members to be independent with no personal financial interest, other than as shareholders, in the committee's decisions. Further detail on the activities of the committee in 2024 is set out in the remuneration committee report on **page 88**.

During 2024 Ben Mathews, who was employed by the company and reported to the chair of the board, acted as secretary to the remuneration committee.

The committee also received advice on various matters relating to the remuneration of executive directors and senior management from Kerry Dryburgh, EVP people, culture & communications and Ashok Pillai, SVP reward.

PricewaterhouseCoopers LLP (PwC) continued to provide independent advice to the committee in 2024. PwC advice included, for example, support with remuneration benchmarking and updates on market practice. PwC is a member of the Remuneration Consulting Group and, as such, operates under the code of conduct in relation to executive remuneration in the UK. The committee is satisfied that the advice received is objective and independent. The committee is comfortable that the PwC engagement partner and team who provide remuneration advice to the committee do not have connections with the company or its directors that may impair their independence.

Total fees or other charges (based on an hourly rate) for the provision of remuneration advice to the committee in 2024 (save in respect of legal advice) were £88,751 to PwC. Freshfields LLP (Freshfields) provided legal advice on specific compliance matters to the committee. PwC and Freshfields provide other advice in their respective areas to the group.

Considerations related to the UK Corporate Governance Code

When setting the 2023 policy, the committee concluded that a scorecard-based approach to setting targets and measuring outcomes helps it to engage transparently with shareholders and the wider workforce on remuneration. Thus, bp continues to operate a simple, clear structure of market-aligned salary with annual and three-year performance-based incentives. Risks are managed through careful setting of performance measures and targets and the committee retains the exercise of its discretion in assessing outcomes. These are complemented with robust malus and clawback measures. Remuneration outcomes are predictable, as shown in the implementation charts of the 2023 policy, and proportional by virtue of the challenging performance levels required to achieve target pay outcomes. Through material weighting in measures related to safety, sustainability and strategy, as shown on **page 104**, remuneration aligns closely with bp's culture, as expressed through our purpose and ambition.

Shareholder engagement

Throughout 2024 the committee engaged frequently on remuneration policy and approach with bp's largest shareholders, as well as their representative bodies. This dialogue will continue throughout 2025. The table below shows the recent votes on the directors' remuneration report and policy.

Year	% vote 'for'	% vote 'against'	Votes withheld
2024 – Directors' remuneration report	95.88%	4.12%	37,229,024
2023 – Directors' remuneration policy	94.23%	5.77%	36,921,641

Service contracts and letters of appointment

The service contracts of executive directors do not have a fixed term. Service contracts for each executive director are available for shareholders to view upon request at the company's registered office. Each executive director's service contract contains a 12-month notice period. Consistent with the best interests of the group, the committee will seek to minimize termination payments.

	Date of contract	Effective date
Murray Auchincloss	17 Jan 2024	17 Jan 2024
Kate Thomson	2 Feb 2024	2 Feb 2024

The non-executive directors (NEDs) have letters of appointment, which are available for shareholders to view upon request at the company's registered office. All directors are subject to annual re-election by shareholders at the annual general meeting. Normally, NEDs will be encouraged to serve for up to nine years from their appointment in line with the provisions of the 2018 Code, subject to annual re-election.

External appointments

The board supports executive directors taking up appointments outside the company to broaden their knowledge and experience. Each executive director is permitted to retain any fee from their external appointments. Such external appointments are subject to agreement by the chair and reported to the board. Any external appointment must not conflict with a director's duties and commitments to bp. Details of appointments as NEDs of publicly listed companies during 2024 are shown below.

	Appointee company	Additional position held at appointee company	Total fees, £
Murray Auchincloss[a]	Aker BP ASA[b]	Director	0
Kate Thomson	Aker BP ASA[b]	Director	0

a Murray resigned from this position during 2024.
b Held as a result of the company's shareholding in Aker BP ASA.

This directors' remuneration report was approved by the board and signed on its behalf by Ben J.S. Mathews, company secretary, on 6 March 2025.

Other disclosures

Appointment and succession plans

The chair, senior independent director (SID) and other independent non-executive directors (NEDs) each have letters of appointment with BP p.l.c. and do not serve, nor are they employed, in any executive capacity by bp. In line with the UK Corporate Governance Code (Code), bp proposes all directors for annual re-election by shareholders at the Annual General Meeting (AGM), where letters of appointment for each NED are available for inspection. Details on the skills and experience of each director seeking election or re-election, as well as their individual contributions to the long-term success of the company, are set out in the Notice of AGM. In accordance with the Code, NEDs would not be expected to serve beyond nine years unless there are exceptional circumstances. On behalf of the board, the people, culture and governance committee reviews the formal appointment process and succession plans for the board. Appointments and succession plans are both based on merit and assessed against objective criteria with the promotion of diversity, equity and inclusion as central considerations. This includes diversity of gender, social and ethnic backgrounds as well as cognitive and personal strengths. In reviewing appointments and succession plans, due consideration is given to ensure the smooth transition of board members with specific responsibilities (e.g. committee chair roles) by allowing sufficient time for a detailed handover. This is balanced by the need to have new board members join at regular intervals such that over time there is a controlled approach to board members reaching the end of their tenure. All new directors receive a formal induction, tailored to their individual needs, skills and experience, taking account of any committees they join. These inductions include one-to-one meetings with members of the board and leadership team together with select members of senior management. Feedback is sought from directors undertaking their induction programmes to ensure they are continually updated and improved.

Further detail on board succession and tenure can be found in the people, culture and governance committee report on **page 87** and board at a glance disclosure on **page 71,** respectively.

Time commitments

The expectation regarding time commitment for NEDs to effectively discharge their duties is set out in the directors' letters of appointment. The time commitment varies with the demands of bp business and other events. The NEDs' external time commitments – whether through executive, non-executive, advisory or other roles – are regularly reviewed by the company secretary to ensure that directors are able to allocate appropriate time to bp. A register of directors' time commitments and conflicts is maintained and is also reviewed annually by the people, culture and governance committee. The review process takes into account outside appointments and other external commitments and considers the complexity of the organization, the nature of the role, the sector (especially regulated and/or potentially competing sectors) and any leadership roles (e.g. a chair position). NEDs are also required to consult with the company secretary and chair before accepting any other role that may impact their ability to commit appropriate time to bp. The process for the approval of any new external appointment, significant or otherwise, for an existing director assesses the impact of that appointment on the director's time in order to ensure the director has sufficient capacity for their role with bp. As part of that same review process, a review of independence and potential conflicts of interest is undertaken, taking account of institutional investor and proxy advisor guidance and market best practice. Any external proposed commitments that could exceed the mandates set out in such guidance are given particular consideration. The board was satisfied that significant appointments undertaken during 2024 did not impact the directors' ability to prepare for and attend meetings, engage with stakeholders and participate in learning and development opportunities. The board has concluded that, notwithstanding external appointments held, each director is able to dedicate sufficient time to fulfil their bp duties. In compliance with the Code, none of the executive directors who served during 2024 held more than one non-executive directorship in a FTSE 100 company or other significant appointment throughout their tenure on the board. For more information on the external commitments of bp's directors, see **pages 72-73**.

For information on board meetings held during 2024 and director attendance at board meetings, see **page 71**.

Independence and conflicts of interest

All directors have a statutory duty to exercise independent judgement. Independence of NEDs is crucial in bringing constructive challenge to the chief executive officer (CEO) and the leadership team at board meetings, while providing support and guidance to promote meaningful discussion and, ultimately, informed and effective decision-making. In accordance with the criteria set out in the Code, the chair was considered independent at the time he was appointed. NEDs are required to provide sufficient information to allow the board to evaluate their independence prior to and following their appointment. In addition, each director has a statutory duty to disclose actual or potential conflicts of interest. Formal procedures are in place for new potential conflicts to be reported and recorded during the year. As a consequence of regular reviews in 2024, the board is satisfied that there were no matters giving rise to conflicts of interest which could not be authorized by the board. It has therefore concluded that all bp NEDs are independent.

Reporting in line with UK Listing Rule 6.6.6R(9)

As at 31 December 2024, 55% of the board comprises women, our senior independent director (SID) and chief financial officer (CFO) are women and three directors identify as from an ethnic minority background. Data for the below tables is collected on an annual basis through a standardized process under which each member of the board and executive management is asked to self-declare, or elect not to declare, their ethnic background and gender identity or sex. The information is correct as at 31 December 2024. For the purposes of this table, executive management includes bp's leadership team and the company secretary.

Gender identity or sex	Number of board members	Percentage of the board	Number of senior positions on the board (CEO, CFO, SID and chair)	Number in executive management	Percentage of executive management
Men	5	45%	2	6	55%
Women	6	55%	2	5	45%
Other categories	–	–	–	–	–
Not specified/prefer not to say	–	–	–	–	–
Ethnic background					
White British or other white (including minority-white groups)	8	73%	100%	9	82%
Mixed/Multiple Ethnic Groups	–	–	–	–	–
Asian/Asian British	3	27%	–	1	9%
Black/African/Caribbean/Black British	–	–	–	1	9%
Other ethnic group	–	–	–	–	–
Not specified/prefer not to say	–	–	–	–	–

Directors' statements

Statement of directors' responsibilities

The directors are responsible for preparing the annual report and the financial statements in accordance with applicable law and regulations. The directors are required by the Companies Act 2006 to prepare financial statements for each financial year that give a true and fair view of the financial position of the group and the parent company and the financial performance and cash flows of the group and parent company for that period. Under that law they are required to prepare the consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the United Kingdom and applicable law and have elected to prepare the parent company financial statements in accordance with applicable United Kingdom law and United Kingdom accounting standards (United Kingdom generally accepted accounting practice), including FRS 101 'Reduced Disclosure Framework'. In preparing the consolidated financial statements the directors have also elected to comply with IFRS as issued by the International Accounting Standards Board (IASB) and IFRS as adopted by the European Union (EU).

In preparing those financial statements, the directors are required to:

- Select suitable accounting policies and then apply them consistently.
- Make judgements and estimates that are reasonable and prudent.
- Present information, including accounting policies, in a manner that provides relevant, reliable, comparable and understandable information.
- Provide additional disclosure when compliance with the specific requirements of IFRS is insufficient to enable users to understand the impact of particular transactions, other events and conditions on the group's financial position and financial performance.
- State that applicable accounting standards have been followed, subject to any material departures disclosed and explained in the parent company financial statements.
- Prepare the financial statements on the going concern basis unless it is inappropriate to presume that the company will continue in business.

The directors are responsible for keeping adequate accounting records that disclose with reasonable accuracy at any time the financial position of the group and company and enable them to ensure that the consolidated financial statements comply with the Companies Act 2006 and the parent company financial statements comply with the Companies Act 2006. They are also responsible for safeguarding the assets of the group and company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

Having made the requisite enquiries, so far as the directors are aware, there is no relevant audit information (as defined by Section 418(3) of the Companies Act 2006) of which the company's auditors are unaware, and the directors have taken all the steps they ought to have taken to make themselves aware of any relevant audit information and to establish that the company's auditors are aware of that information.

Each of the current directors, whose names and functions are listed on **pages 72-73**, confirms that to the best of their knowledge:

- The consolidated financial statements, prepared on the basis of IFRS as issued by the IASB, IFRS as adopted by the United Kingdom and EU and in accordance with the provisions of the Companies Act 2006 as applicable to companies reporting under international accounting standards, give a true and fair view of the assets, liabilities, financial position and profit or loss of the group.
- The parent company financial statements, prepared in accordance with United Kingdom generally accepted accounting practice, give a true and fair view of the assets, liabilities, financial position, performance and cash flows of the company.
- The management report, which is incorporated in the strategic report and directors' report, includes a fair review of the development and performance of the business and the position of the group, together with a description of the principal risks and uncertainties that they face.

Helge Lund
Chair
6 March 2025

UK Corporate Governance Code compliance

Throughout 2024 bp applied the principles of the UK Corporate Governance Code 2018 (Code) and has complied with all the provisions. The information set out in the directors' report, including the committee reports on **pages 80-110**, is intended to provide an explanation of how bp applied the principles and complied with the provisions of the Code during the year. The Code can be found on the Financial Reporting Council website: frc.org.uk.

Risk management and internal control

Under the Code, the board is responsible for the company's risk management and internal control systems. In discharging this responsibility the board, through its governance principles, requires the chief executive officer to operate the company with a comprehensive system of controls and internal audit and to identify and manage the risks, including emerging risks, that are material to bp. In turn, the board, through its monitoring processes, satisfies itself that these material risks are identified and understood by management and that systems of risk management and internal control are in place to mitigate them. These systems are reviewed periodically by the board, have been in place for the year under review and up to the date of this report and are consistent with the requirements of Principle O of the Code.

The board has processes in place to:

- Assess the principal and emerging risks facing the company.
- Monitor the company's system of internal control (which includes the ongoing process for identifying, evaluating and managing the principal and emerging risks).
- Review the effectiveness of that system annually.

Acquired businesses which have not transitioned into bp's system of internal control and non-operated joint ventures and associates★ have not been dealt with as part of this process.

A description of the principal risks facing the company, including those that could potentially threaten its business model, future performance, solvency or liquidity, is set out in risk factors on **pages 65-67.** During 2024 the board undertook a robust assessment of the principal and emerging risks facing the company. The principal means by which these risks are managed or mitigated are set out on **pages 61-64**.

In assessing the risks faced by the company and monitoring the system of internal control, the board and the audit and safety and sustainability committees requested, received and reviewed reports from executive management, including management of the business segments, corporate activities and any functions, at their regular meetings. A report by each of these committees, including its activities during the year, is set out on **pages 80-85**.

During 2024 the committees, as relevant, also met with management, the SVP internal audit and other monitoring and assurance functions (including group ethics & compliance, safety and operational risk, group control, group legal and group risk) and the external auditor. Responses by management to incidents that occurred were considered by the relevant committee or the board, as appropriate.

At a meeting in March 2025, the audit committee considered reports from the group risk function on the system of internal control and the function's categorization of significant failings or weaknesses. The audit committee also considered a report from internal audit on their assessment of bp's systems of internal control and risk management, based on audit work conducted during 2024. In considering these reports and assessments, the audit committee noted that bp's systems of internal control and risk management are designed to manage, rather than eliminate, the risk of failure to achieve business objectives and can only provide reasonable, and not absolute, assurance against material misstatement or loss.

The board then considered the review undertaken by the audit committee and the proposed disclosures outlining the company's risk management and internal control systems prior to publication of the annual report and accounts.

A statement regarding the company's internal controls over financial reporting is set out on **page 336.**

Longer-term viability

In accordance with provision 31 of the Code, the directors have assessed bp's prospects both at an operating and strategic level with some business planning processes extending out beyond the next ten years. However, the directors believe that a viability assessment period of three years remains appropriate given the nature of our business and exposure to short-term commodity pricing. This assessment is based on management's reasonable expectations of the position and performance of the company over this period, its internal detailed budgets and planning timeframes and the targets and aims that it has set out.

Our risk management system, described in how we manage risk starting on **page 61**, outlines our risk identification, assessment and management approach for all risks, including our principal risks, described starting on **page 65**.

Taking into account the company's current position and its principal risks, the directors have a reasonable expectation that the company will be able to continue in operation and meet its liabilities as they fall due over the next three years.

The directors' assessment included a review of the potential financial impact of, and the financial headroom that could be available in the event of, the most severe but plausible scenarios that could threaten the viability of the company. The assessment took into consideration the robust financial position of the group and the potential mitigations that management reasonably believes would be available to the company over this period. Mitigations considered include use of cash, access to debt facilities and credit lines, raising of capital, reductions in capital expenditure, divestments and dividend reductions.

The scenarios that have been modelled are based on the most severe but plausible outcomes and associated costs are based on actual experience where possible. The scenarios link to one or more of our principal risks described on **pages 65-67** and have been considered individually and as a cluster of events. They include:

- A significant process safety incident when operating facilities, drilling wells or transporting hydrocarbons. Process safety, personal safety and environmental risks, see **page 67**.
- A sustained significant decline in oil prices over three years. Prices and markets, see **page 65**.
- A significant cyber security incident. Digital infrastructure, cyber security and data protection, see **page 66**.
- A loss of a significant market or producing asset for six months. Prices and markets, see **page 65**.

As an example of a cluster of events, bp models a risk scenario involving a significant process safety incident (when operating facilities, drilling wells or transporting hydrocarbons) during a low-price environment (i.e. where there is a sustained significant decline in oil prices over a three-year period).

The directors also considered the impact on viability from an extended pandemic scenario, as well as the potential risks associated with climate change and the transition to a lower carbon economy. They consider that the most likely impacts of these risks are broadly captured and modelled through the sustained low oil price and loss of a producing asset scenarios.

In assessing the prospects of the company, the directors noted that such assessment is subject to a degree of uncertainty that can be expected to increase looking out over time and, accordingly, that future outcomes cannot be guaranteed or predicted with certainty.

Fair, balanced and understandable

The board considers the annual report and financial statements, taken as a whole, is fair, balanced and understandable and provides the information necessary for shareholders to assess the company's position and performance, business model and strategy.

Going concern

In accordance with provision 30 of the Code, the directors consider it appropriate to adopt the going concern basis of accounting in preparing the financial statements.

Forecast liquidity has been assessed under a number of stressed scenarios to support this assertion. 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 financial statements even if the Brent price fell to zero. For further information on financial risk factors, including liquidity risk, see Financial statements – **Note 29**.

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Consolidated financial statements of the bp group

Notes on financial statements

Supplementary information on oil and natural gas (unaudited)

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

Consolidated financial statements of the bp group

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

Report on the audit of the financial statements

1. Opinion

In our opinion:

- the financial statements of BP p.l.c. (the 'parent company' or 'bp') and its subsidiaries (the 'group' or 'bp') give a true and fair view of the state of the group's and of the parent company's affairs as at 31 December 2024 and of the group's profit for the year then ended;
- the group financial statements have been properly prepared in accordance with United Kingdom adopted international accounting standards and IFRS Accounting Standards 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 Generally Accepted Accounting Practice, including FRS 101 'Reduced Disclosure Framework'; and
- 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 38 to the financial statements, including a summary of material accounting policy information and
- parent company related Notes 1 to 14 to the financial statements, including a summary of material accounting policy information.

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 IFRS Accounting Standards 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, with the exception of Deloitte UAE providing an additional service of rolling forward a BP p.l.c.'s subsidiary's financial statements. The service was administrative in nature and there were no calculations or judgements applied when carrying out this exercise. In our opinion, based on no fees being charged for the services and the size of the component, the impact of providing the services was immaterial and inconsequential, however this is a breach, albeit insignificant, of the Ethical Standard. Following investigation, we have concluded in agreement with the Audit Committee that given the size of the services provided and their potential impact, as well as the safeguards in place, our objectivity and impartiality has not been impaired, and we believe that a reasonable and informed third party with knowledge of all relevant facts and circumstances would conclude that we are capable of exercising objective and impartial judgement on all matters related to the audit.

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

3. Summary of our audit approach

Key audit matters	The key audit matters that we identified in the current year were: • potential impact of climate change and the energy transition • impairment of upstream oil and gas property, plant and equipment (PP&E) assets • decommissioning provisions • valuation of commodity financial derivatives, where fraud risks may arise in revenue recognition, and • management override of controls. In the current year, we re-considered whether the accounting for complex transactions remains a key audit matter. While the group continues to enter into such transactions, these transactions have significantly reduced in magnitude compared with the prior year. Consequently, accounting for these transactions was not included as a key audit matter, as they do not have a material impact on the group's financial statements. We designed and performed audit procedures relative to the risk levels determined through the application of our consistent framework for evaluating complex transactions. These procedures were adjusted, as necessary, based on the nature, scale, and complexity of the transactions assessed during the year. All other 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 the respective sections below.
Materiality	The materiality that we used for the group financial statements was $800 million (2023 $1,000 million) which was determined based on cash flow from operations and underlying replacement cost profit before interest and tax. We adopted a different basis to determine materiality used to audit the group financial statements this year due to the impact of changing macroeconomic conditions, one-off transactions and strategic decisions on the group's profit before tax. In the prior year we determined materiality based on profit before tax and underlying replacement cost profit before interest and tax.
Scoping	Our scope covered 178 consolidation units (cons units). Of these, 153 were subject to audits of specified account balances and 25 were subject to specified audit procedures by the component audit teams or group audit team. These covered 69% of revenue, 73% of PP&E and 72% of profit before tax. The remaining 765 cons units were subject to other procedures, including performing analytical reviews, making inquiries of management, and evaluating and testing management's group-wide controls.

4. Conclusions relating to going concern

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

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

- assessing the financing facilities including the nature of the facilities and repayment terms;
- assessing whether the impact of potential margin calls in respect of derivative exchange contracts used to risk manage the physical portfolio has been appropriately considered given price volatility;
- assessing management's identified potential mitigating actions and the appropriateness of the inclusion of these in the going concern assessment;
- testing the clerical accuracy of the going concern model;
- assessing the historical accuracy of forecasts prepared by management;
- performing our independent sensitivity analysis; and
- assessing the disclosures made within the financial statements.

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.

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

5.1 Potential impact of climate change and the energy transition (impacting PP&E, goodwill, intangible assets and provisions) – Notes 1, 4, 12, 14, 15 and 33 to the financial statements	
Key audit matter description	Climate change impacts bp's business in a number of ways as set out in the strategic report on pages 1-68 of the Annual Report and Note 1 of the financial statements on page 145. It represents a strategic challenge and a key focus of management. The related risks that we have assessed for our audit are as follows: • Forecast assumptions used in assessing the value-in-use of oil and gas PP&E assets within bp's balance sheet for impairment testing, particularly oil and gas price assumptions and their interrelationship with forecast emissions costs, may not appropriately reflect changes in supply and demand due to climate change and the energy transition (see 'Impairment of upstream oil and gas PP&E assets' below). • The timing of expected future decommissioning expenditures in respect of oil and gas assets may need to be brought forward with a resulting increase in the present value of the associated liabilities due to the impact of climate change. In addition, 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 increased 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 $4.4 billion total exploration and appraisal (E&A) assets capitalised as at 31 December 2024 (2023 $4.3 billion) is 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 or lower forecast future oil and gas prices. 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 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 146, management has concluded that demand for refined products is expected to remain sufficient for the existing refineries to continue operating for the duration of their remaining useful lives and hence no changes to the useful economic lives of its refinery assets were required. • The carrying value of bp's refining assets within PP&E may no longer be recoverable, due to changes in supply and demand which arise among other things as a consequence of climate change and the energy transition. Management identified impairment indicators in respect of the Gelsenkirchen refinery in Germany during the year and, as a result, an impairment test was performed to assess the recoverability of the Gelsenkirchen refinery carrying value. As disclosed in Note 4 to the accounts on page 166 management has recorded an impairment charge of $0.8 billion (2023 $1.3 billion) in respect of the Gelsenkirchen refinery, primarily driven by changes in economic assumptions. At 31 December 2024 management identified an impairment indicator for all of its other refineries due to a reduction in the local marker margins. The impairment tests performed by management to assess the recoverability of the carrying value of these refineries did not result in any additional impairment charges being recognised. • The total goodwill balance as at 31 December 2024 is $14.9 billion (2023 $12.5 billion), of which $7.2 billion relates to upstream oil and gas assets (2023 $7.0 billion). The carrying value 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') and gas & low carbon energy ('G&LCE'), goodwill is allocated to hydrocarbon CGUs in aggregate at the respective segment level. Goodwill related to low carbon energy investments is held separately within the G&LCE segment. The most significant assumption in the hydrocarbon related 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 179. The customers & products (C&P) segment has a goodwill balance of $5.5 billion (2023 $5.4 billion), of which the most significant element is $2.6 billion relating to the Castrol business (2023 $2.7 billion). 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. Subsequent to the year end, on 26 February 2025 the group announced a strategy reset, with a consequent impact on the group's key targets and metrics for 2025 and beyond. This post balance sheet event has been considered by management in the context of forecasts and assumptions as they relate to the 2024 financial statements and the matters noted above. 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. This matter was also discussed by the Audit Committee on page 84.

How the scope of our audit responded to the key audit matter	**Overall response** 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. We also continued to utilise a climate change steering committee comprising a group of senior partners and specialists with specific climate change and technical audit and accounting expertise within Deloitte to provide an independent challenge to our key decisions and conclusions with respect to this area. **Audit procedures** The audit response related to two of the audit risks identified is set out under the key audit matters for 'Impairment of upstream oil and gas PP&E assets' on pages 121-123 and 'Decommissioning provisions' on pages 124-125. Other procedures are as follows: In respect of the recoverability of E&A assets capitalised as at 31 December 2024: • We tested the relevant controls within the group's E&A write-off and impairment assessment processes. • We challenged and evaluated management's key E&A judgements with regards to the impairment criteria of IFRS 6. Where impairment indicators were identified, 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 assessing licence documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms. 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 2024 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 considered the impact of potential changes in supply and demand on the group's refining portfolio and assessed internal and external market studies of future supply and demand. In relation to the refinery impairment tests performed by management, our audit procedures included: evaluating the valuation methodology and testing the integrity and mechanical accuracy of the impairment models; assessing the appropriateness of key assumptions and inputs to the impairment models, notably forecast local refining marker margins, discount rate and energy input costs, challenging and evaluating management's assumptions by reference to third party data where available and involvement of our valuation specialists; and evaluating management's ability to forecast future cash flows and margins by comparing actual results with historical forecasts and tested management's internal controls over the impairment test and related inputs. 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 in respect of which reasonably possible changes due to the energy transition and other climate change factors could cause goodwill to be materially misstated. We assessed the impact of climate change on C&P segment activities and we have not noted any factors to indicate impairment of goodwill due to climate change. 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 • assessing the contingent liability disclosures in the annual report on pages 217-219. With regard to the consideration of the impact of the post balance sheet strategic announcement by the group, we performed procedures to assess the reasonableness and completeness of management's analysis as to the impact on forecasts and assumptions underpinning the judgements identified above. 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; and (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 are satisfied: • with the results of our procedures relating to the carrying value of refining assets and that the impairments recorded are reasonable; • 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; • that management's assessment of the impact of the group's post balance sheet strategy update on the forecasts and assumptions as they relate to the judgements are reasonable and complete; 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, with its sustainability aims of 'net zero operations' and 'net zero sales'. 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 five years and the refining assets (within the C&P segment) is eleven years.

5.2 Impairment of upstream oil and gas property, plant and equipment (PP&E) assets – Notes 1, 4 and 12 to the financial statements	
Key audit matter description	The group balance sheet as at 31 December 2024 includes PP&E of $100 billion (2023 $105 billion), of which $56 billion (2023 $62 billion) is oil and gas properties. Management's best estimate oil and gas price assumptions for value-in-use impairment tests were revised in 2024 as set out in Note 1 on page 152, although the revisions were not significant. Management has also determined bp's 'best estimate' discount rate assumptions, as set out in Note 1 on page 152. bp's post-tax discount rate used for impairment testing for oil and gas assets in 2024 remained unchanged from prior year at 8% (2023: 8%). Pre-tax discount rates applied in impairment tests were revised in some regions to reflect changes in local tax rates and country risk premiums, however the impact of these revisions was insignificant. Reserves estimates for all oil and gas fields were also reviewed and updated where necessary at year-end. Management judged that in aggregate, the year-end oil and gas price assumption revisions, changes to pre-tax discount rates for certain regions due to country risk premium or tax rate changes, and changes to other input assumptions including reserves reductions on several key fields, all combined to constitute an impairment trigger for all oil and gas cash generating units (CGUs). As a result of testing performed during 2024, $2.0 billion (2023 $3.6 billion) of oil and gas CGU net impairment charges were recognised, principally due to certain discount rate revisions, an increase in certain capital expenditure forecasts and operating expenditure forecasts and certain reserves write downs. 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 ongoing geo-political conflicts. 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 valuation. There is also a risk that management's oil and gas price related disclosures are not reasonable. 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 146, 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. **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 judgemental. There is a risk that material misstatements could arise from unreasonable production forecasts for individually material CGUs and/or from the aggregation of systematic flaws in bp's reserves and resources estimation policies across the OP&O and G&LCE segments. We identified certain individual CGUs with a total carrying value of $9 billion (2023 $18 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. These CGUs have been subjected to $9 billion worth of previous impairments and as such, 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 was also individually materially sensitive to the discount rate assumption. Accordingly, we identified these as significant audit risks. We also identified CGUs with a further $2 billion (2023 $2 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 153. 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 forecast assumptions such as oil and gas prices, discount rates and reserves estimates, which are inherently judgemental and complex for management to estimate and challenging to audit. Additionally, the magnitude of the potential misstatement risk remains material to the group. This matter was discussed by the Audit Committee on page 85.

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

How the scope of our audit responded to the key audit matter	We tested relevant internal controls over the estimation of oil and gas prices, discount rates, and reserve and resources estimates, as well as relevant 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 and evaluating 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 29 in Baku during November 2024. 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 and evaluated management’s judgement, described in Note 1 on page 146, 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 obtained evidence supporting that oil and gas price forecasts included in our reasonable range 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 Note 1, 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. • When performing procedures over specific assets, 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 Note 1, 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 for reasonableness; • 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 and evaluated a sample of reports provided by management’s external reserves experts and assessed the scope of work and findings of these third parties; • assessed the competence, capability and objectivity of bp’s internal and external reserve experts, through understanding their relevant professional qualifications and experience; • assessed whether management’s production forecasts are consistent overall with bp’s strategy; • compared the production forecasts used in the impairment tests with management’s approved reserves and resources estimates; and • performed a retrospective assessment in order to assess management's ability to accurately estimate reserves and resources and to check for indications of estimation bias over time.

Key observations	**Oil and gas prices** For the purpose of PP&E impairment tests, management is required under IAS 36 to apply its current ‘best estimate’ of future oil and gas prices. We determined that bp’s ‘best estimate’ assumptions are reasonable when compared against a range of third party forecasts and peer information that we identified as being appropriate for this purpose. In forming this view, we included each forecaster’s ‘base case’, ‘central case’ or ‘most likely’ estimate. We further observed that, as well as publishing a ‘base case’, ‘central case’ or ‘most likely’ estimate, certain third party price forecasters including the IEA published other price forecasts including some that were stated as, or were interpreted by us as being, Paris ‘well below 2°C goal’ or Paris ‘1.5°C ambition’ scenarios. We observed that none of those third party forecasters described their ‘Paris consistent’ scenarios as their ‘base case’, ‘central case’ or ‘most likely’ estimate. Management notes on page 145 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 bp’s Brent price assumptions, whilst these were within the lower half of our range of ‘best estimate’ forecasts described above, they were within the higher half of our range of Paris ‘well below 2°C goal’ and ‘1.5°C ambition’ scenarios. For Henry Hub gas, management’s updated gas price assumptions sit towards the top of our range until 2040 and then towards the middle until 2050. The positioning of bp’s revised oil and gas forecasts within the range is broadly consistent with bp’s positioning in the prior period range. We also noted 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. By inquiry and analysis, we confirmed that the third party oil and gas price forecasts used to develop our independent range are on a net producer price basis. Accordingly, we are satisfied management’s judgement is reasonable that the potential impact of further emission costs being borne by bp is not expected to have a material impact on the group’s oil and gas CGU carrying values. We reviewed the disclosures included in Note 1 to the accounts in respect of oil and gas price assumptions, including the sensitivity analysis presented therein. We observed that management’s downside sensitivity, in which oil and gas prices are lower than the ‘best estimate’ in all future periods, is close to the bottom end of our range of third party Paris ‘well below 2°C goal’ and Paris ‘1.5°C ambition’ scenarios for both Brent oil and Henry Hub gas. **Discount rates** bp’s post-tax nominal 8% discount rate used for impairment testing for oil and gas assets, was within the independent range calculated by our valuation specialists. We were also satisfied with the calculation of country risk premia. Accordingly, we are satisfied with the discount rates used in the impairment charge and impairment reversal testing. **Reserves and resources** We assessed the production forecasts used in the oil and gas CGU valuations that we tested to be reasonable and appropriately risked where applicable, for the purposes of management’s impairment tests. We observed that in aggregate, management’s production forecasts, as utilised in year-end oil and gas CGU impairment testing, are aligned with bp’s best estimate of the future production of their existing oil and gas portfolio.

5.3 Decommissioning provisions – Note 1 and 23 to the financial statements

<table>
<tr><td>Key audit matter description</td><td>
A decommissioning provision of $11.8 billion is recorded in the financial statements as at 31 December 2024 (2023 $12.4 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.
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.
The estimated undiscounted cost of the obligations and the timing of future payments are set out in Note 1 on page 159. 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 the discount rate used in calculating its decommissioning provisions from 4.0% as at 31 December 2023 to 4.5% as at 31 December 2024. The increase was primarily driven by increased US treasury bond rates.
Additionally, bp is exposed to decommissioning obligations that could revert back to the group 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.
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 159 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.
This matter was discussed by the Audit Committee on page 85.
</td></tr>
<tr><td>How the scope of our audit responded to the key audit matter</td><td>
Long-term inflation rate

We tested the relevant 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 the general long term inflation rate assumption used of 2.0%, comparing it against latest external market data.
We made inquiries and evaluated the competence, capability 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 and evaluated management’s assessment of the impact this will have on the decommissioning market and the related inflation assumption.
We analysed historical trends of rig market rates against oil prices and historical inflation to evaluate management’s assumption that the decommissioning inflation assumption does not inflate at the same rate as general inflation.

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	Cost and timing estimates • We tested the relevant 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 the reasonableness of changes in key cost assumptions including rig rates, vessel rates, well plug and abandonment duration and non-productive time 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 disclosure of the estimated undiscounted cost of its obligations and the timing of future decommissioning payments. **Discount rates** • We tested the relevant controls related to the determination of the discount rate assumption. • We assessed the reasonableness of management's methodology for determining the discount rate and recalculated the discount rate with reference to independent third party data, most notably US treasury bond yields. **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 to assess the 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 plans 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.
Key observations	We concluded that the assumed inflation rate of 1.5% remains reasonable as a long-term inflation rate for decommissioning liabilities. 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. 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 159 with respect to the estimated undiscounted cost of bp's decommissioning obligations and the timing of future decommissioning payments are consistent with these conclusions. Based on our audit procedures, we consider bp's 4.5% discount rate to be reasonable. 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. In respect of the group's refining assets, taking into consideration both the IEA 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 determine closure dates for the remaining operational refineries or 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.

5.4 Valuation of commodity financial derivatives, where fraud risks may arise in revenue recognition – Notes 1, 29 and 30 to the financial statements

Key audit matter description	bp's supply, trading and shipping (ST&S) function is responsible for globally trading and risk managing the group's owned as well as third party production. To discharge this responsibility, ST&S regularly executes commodity contracts, physically settled or otherwise, which are accounted for as a derivative and fair valued under IFRS 9. These contracts, therefore, result in unrealised gains/losses that are recognised on account of fair value movements in the associated derivative assets and liabilities. Determining the fair value of derivative assets and liabilities can be complex and subjective, particularly where the valuation is dependent on significant inputs which are not observable and are classified as level 3 in the fair value hierarchy set out in IFRS 13. This degree of subjectivity also makes such fair value estimates liable to potential fraud by management incorporating bias in the inputs used in determining fair values. Given the significant judgements, sensitivity to management assumptions, and the absolute value associated with these positions, we have identified a significant risk in respect of certain financial instruments where the valuation is dependent on significant unobservable inputs. Fair value measurements associated with unrealised commodity contracts are also impacted by the macroeconomic sentiment and outlook. In 2024, commodity markets continued to experience periods of volatility due to continuing uncertainty resulting from the planned energy transition, macro-economic factors such as inflation and interest rates, and disruptions in global supply due to geopolitical conflicts. In response to the volatility observed, we focused our audit efforts on the valuation of commodity derivatives and designed procedures to test for management bias. As at 31 December 2024, the group's total level 3 derivative financial assets were \$16.0 billion (2023 \$9.2 billion) and level 3 derivative financial liabilities were \$14.4 billion (2023 \$7.1 billion). This matter was discussed by the Audit Committee on page 85.
How the scope of our audit responded to the key audit matter	In response to the above, we analysed the population of these instruments to assess the level of unobservability of the inputs used in their valuation and then further disaggregated the population into different risk populations which in turn drove the nature, timing and extent of our audit procedures. To address the complexities associated with auditing the valuation of instruments dependent on significant unobservable inputs, we included valuation specialists with significant quantitative and modelling expertise to assist in performing our audit procedures. Our valuation audit work included the following control and substantive procedures: • We tested the group's valuation relevant controls including: – the model certification control, which is designed to review a model's theoretical soundness and the appropriateness of its valuation methodology; and – the 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 valuation testing procedures at interim and year-end balance sheet dates, including: – evaluating management's valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period; – engaging our valuation specialists to challenge models, develop fair value estimates and evaluate consistency in management's modelling and input assumptions throughout the year; – comparing management's input assumptions against the expected assumptions of other market participants and observable market data; – independently validating price points on pricing curves; and – analysing whether there was any indication of management bias through evaluating the distribution of valuation differences where relevant.
Key observations	Based on the evaluation of the results of the procedures noted above, we concluded that management's valuations relating to commodity derivatives were appropriate and we did not identify evidence of management bias in the valuation estimates or accounting entries that we tested.

5.5 Management override of controls (potentially impacting all financial statement accounts)	
Key audit matter description	We conducted an assessment of the fraud risks arising from management override of controls by considering potential areas where the group's financial statements could be manipulated. In performing this assessment, we considered pressures or incentives to achieve certain measures due to the remuneration arrangements of people in Financial Reporting Oversight Roles (FRORs), including management and senior executives, as well as other incentives which could exist in light of bp's share buyback commitments communicated to its shareholders. Our considerations included the potential for: • inappropriate accounting estimates and judgements • the posting of fictitious or fraudulent journal entries or • inappropriate accounting for significant transactions that are outside the normal course of business for the entity. Management has enhanced its control environment in 2024 to address deficiencies identified during prior period audits. During the year, certain deficiencies had yet to be remediated but we have identified mitigating controls to address the risk associated with the deficiencies. These included analytical reviews, controls over closing balances, period-end analytical review controls and certain automated business controls. This area had a significant bearing again this year on the allocation of audit resources and has been discussed with the audit committee throughout the year. Accordingly, we identified this as a key audit matter.
How the scope of our audit responded to the key audit matter	We tested the mitigating controls to respond to the risk of fraudulent journal entries. In addition, we: • made inquiries of individuals with different levels of responsibility 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; • made inquiries of management and others within bp as appropriate, who deal with allegations, if any, of fraud raised by employees or other parties; • used our data analytics tools to select journal entries and other adjustments made at the end of a reporting period, or otherwise having characteristics associated with common fraud schemes, for testing; and • tested journal entries and other adjustments recorded in the general ledger throughout the period, with a particular focus on adjustments that occur late in the financial close process. We assessed accounting estimates for bias. A number of the most significant estimates are covered by the other key audit matters set out above. This assessment included: • evaluating whether the judgements and decisions made by management in making the accounting estimates included in the financial statements, even if they are individually reasonable, indicate a possible bias on the part of bp's management that may represent a risk of material misstatement due to fraud; and • performing a retrospective analysis of management judgements and assumptions related to significant accounting estimates reflected in the financial statements of the prior year. We considered whether there were any significant transactions that are outside the normal course of business, or that otherwise appear to be unusual due to their nature, timing or size. The risks and responses to the revenue recognition risk within the supply, trading and shipping function are set out on page 126.
Key observations	We were able to rely on the mitigating controls tested. Our testing of journal entries and other adjustments, selected through the use of our data analytics tools, did not identify any inappropriate items. We did not identify evidence of overall bias or any significant transactions that are outside the normal course of business 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.

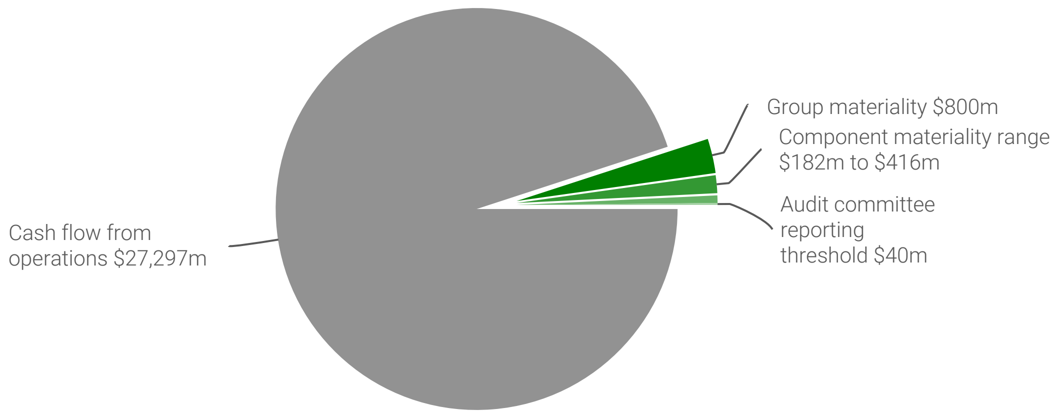
6. Our application of materiality

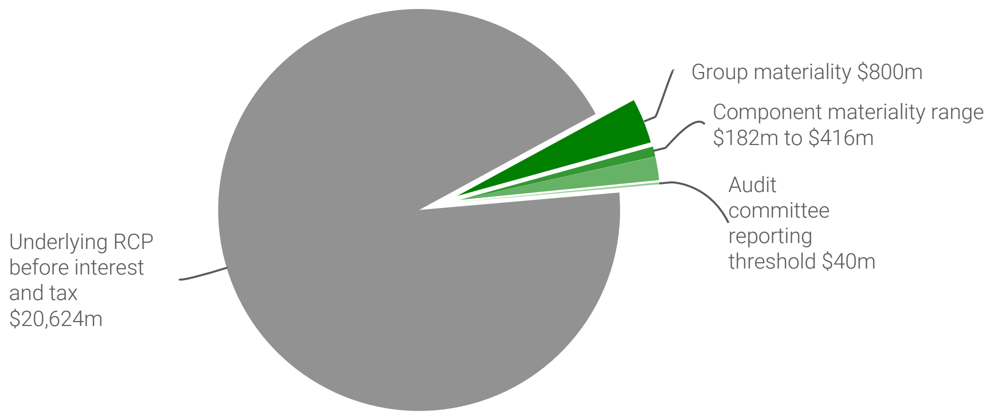
6.1 Materiality

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	In 2024 we set materiality for both the group and parent company at $800 million. In 2023, we used a materiality of $1,000 million for both the group and parent company. The decrease in materiality is due to the downturn in the group's performance compared with prior year.	
Basis for determining materiality	Changing macroeconomic conditions, one-off transactions and strategic decisions had a significant impact on the group's profit before tax in 2024. We therefore determined that it is appropriate to use the benchmarks of most relevance to investors, being cash flow from operations and underlying replacement cost profit before interest and tax. Materiality was determined to be $800 million, which is 2.9% of cash flow from operations (2023 3.1%) and 3.9% of underlying replacement cost profit before tax (2023 3.7%). In 2023, we determined materiality to be $1,000 million, which represented 4.2% of profit before tax and 3.7% of underlying replacement cost profit before tax.	We determined materiality for our audit of the standalone parent using 0.6% (2023 0.8%) of net assets.
Rationale for the benchmark applied	We conducted an assessment of which line items are the most important to investors and analysts by reading analyst reports and bp's communications to shareholders and lenders, as well as the communications of peer companies. Based on our review of analysts' reports, all analysts identified one or more cashflow metrics as a key operating metric, particularly net cash flow from operations. Also, based on our assessment of the latest results announcement Q&As, the focus of the investors has been on cash flow generation and the strength of the balance sheet, particularly from a net debt perspective given the current underlying performance of the group. We therefore focused on cash flow from operations in our determination of materiality for the current year. We further note that the alternative performance 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.	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.





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 materiality for the 2024 audit (2023 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 $40 million (2023 $50 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 940 cons units, a significant portion of our audit planning effort was so that the scope of our work was 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 included the following:

- The determination of significance of an account balance and risks of material misstatement related to it, 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 2023 audit engagement.

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

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For the current year, components have either been subject to audits of one or more classes of transactions, account balances or disclosures, or specific further audit procedures.

As a result, to be able to obtain sufficient, appropriate audit evidence for the purposes of our audit of the financial statements, the group engagement team and component teams performed audits of specified account balances in 153 reporting cons units covering UK, US, Australia, Azerbaijan, Germany, Trinidad and Tobago, Mauritania & Senegal, Indonesia, Egypt, India and Abu Dhabi.

In 2023, we performed full scope audits for 138 reporting cons units which were selected based on their size or risk characteristics. Our full-scope audits were in the UK, US, Australia, Azerbaijan and Germany. In addition, component teams performed audit procedures on specified account balances in 24 cons units also covering Trinidad and Tobago, Mauritania & Senegal, Indonesia, Egypt, India and Abu Dhabi.

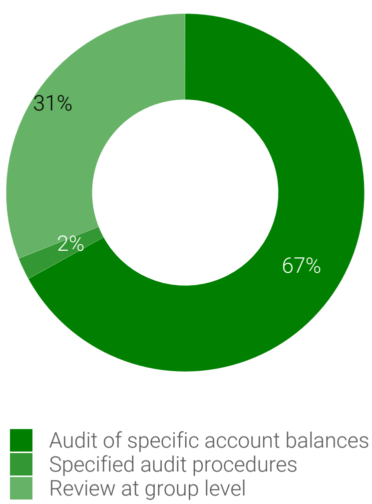
The group engagement team performed audit procedures on specified account balances to component materiality, with certain additional specific procedures performed by component teams, covering an additional 25 cons units (2023 27).

The remaining cons units are not significant individually and include many small, low risk components and balances. On average, they each represent 0.04% of revenue (2023 0.04%), 0.04% of property, plant and equipment (2023 0.03%) and 0.04% of profit before tax (2023 0.04%).

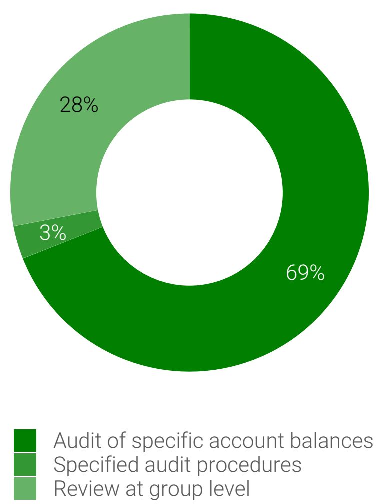
In our assessment of the residual balances not covered by the above procedures, we have considered the risk that there could be undetected and uncorrected misstatements that are material in the aggregate within the large number of geographically dispersed businesses, in particular within the C&P segment. 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 misstatements arising to a sufficiently low level.

Our audit coverage of 'Property, plant and equipment', 'Revenue' and 'Profit before tax' is materially the same as in the prior year.

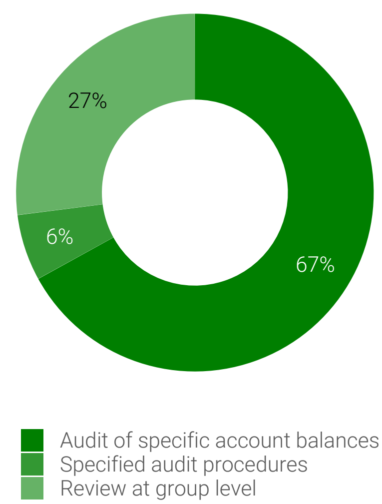
Revenue



Profit before tax



Property, plant & equipment



7.2 Our consideration of the control environment

Our audit approach was generally to place reliance on management's relevant controls over all business cycles affecting in scope financial statement line items. We tested a sample of these controls 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 101 separate IT systems scoped as being relevant to the audit for the following key locations (UK, US, Germany, 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, and having tested controls over access security, change management, data centre operations and network operations, were able to do so.

7.3 Working with other auditors

The group audit team is responsible for the scope and direction of the audit process and providing 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.

Consistent with prior year, the senior statutory auditor and other group audit partners and staff conducted visits to meet with the component teams responsible for the audits of specified account balances during the year. 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 Global Business Services (GBS) locations and senior management from bp.

8. Other information

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

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

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

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

We have nothing to report in this regard.

9. Responsibilities of directors

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

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

10. Auditor's responsibilities for the audit of the financial statements

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

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

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

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

11.1 Identifying and assessing potential risks related to irregularities

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

- our meetings throughout the year with the Group Head of Ethics and Compliance and reviews of bp's internal ethics and compliance reporting summaries, including those concerning investigations;
- enquiries of management, internal audit, and the audit committee, including obtaining and reviewing supporting documentation, concerning the group's policies and procedures relating to:
  - identifying, evaluating and complying with laws and regulations and whether they were aware of any instances of non-compliance;
  - detecting and responding to the risks of fraud and whether they have knowledge of any actual, suspected or alleged fraud; and
  - the internal controls established to mitigate risks related to fraud or non-compliance with laws and regulations;
- 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, 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 valuation of commodity financial derivatives, 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 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 113
- 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 113
- the directors' statement on fair, balanced and understandable set out on page 113
- the board's confirmation that it has carried out a robust assessment of the emerging and principal risks set out on page 112
- the section of the annual report that describes the review of effectiveness of risk management and internal control systems set out on page 112 and
- the section describing the work of the audit committee set out on pages 82-85.

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

14.1 Adequacy of explanations received and accounting records

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

- we have not received all the information and explanations we require for our audit or
- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us or
- the parent company financial statements are not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

14.2 Directors' remuneration

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

We have nothing to report in respect of these matters.

15. Other matters which we are required to address

15.1 Auditor tenure

The board appointed Deloitte as the company's auditor with effect from 29 March 2018 to fill the vacancy arising from the resignation of the previous auditor. On 25 April 2024, 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 2025 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 7 years, covering the years ending 31 December 2018 to 31 December 2024.

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) 4.1.15R – DTR 4.1.18R, these financial statements will form part of the Electronic Format Annual Financial Report filed on the National Storage Mechanism of the FCA in accordance with DTR 4.1.15R – DTR 4.1.18R. This auditor's report provides no assurance over whether the Electronic Format Annual Financial Report has been prepared in compliance with DTR 4.1.15R – DTR 4.1.18R.

Judith Tacon FCA (Senior statutory auditor)
For and on behalf of Deloitte LLP
Statutory Auditor
London, United Kingdom
6 March 2025

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

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 2024 and 2023, 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 2024, 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 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended 31 December 2024, in accordance with United Kingdom adopted international accounting standards and IFRS Accounting Standards 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 2024, 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 6 March 2025 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 2024 includes PP&E, of which $56 billion is oil and gas properties.

Management's best estimate oil and gas price assumptions for value-in-use impairment tests were revised in 2024 as set out in Note 1 on page 152, although the revisions were not significant.

Management have also determined bp's 'best estimate' discount rate assumptions, as set out in Note 1 on page 152. Bp's post-tax discount rate used for impairment testing for oil and gas assets in 2024 remained unchanged from prior year at 8%. Pre-tax discount rates applied in impairment tests were revised in some regions to reflect changes in local tax rates and country risk premiums. Reserves estimates for all oil and gas fields were also reviewed and updated where necessary at year-end.

Management judged that in aggregate, the year-end oil and gas price assumption revisions, changes to pre-tax discount rates for certain regions due to country risk premium or tax rate changes and changes to other input assumptions including reserves reductions on several key fields, all combined to constitute an impairment trigger for all oil and gas cash generating units (CGUs). As a result of testing performed during 2024, $2.0 billion of oil and gas CGU net impairment charges were recognised, principally due to certain discount rate revisions, an increase in certain capital expenditure forecasts and operating expenditure forecasts and certain reserves write downs.

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 ongoing geo-political conflicts. 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 valuation. There is also a risk that management's oil and gas price related disclosures are not reasonable.

Discount rates – Given the long timeframes involved, certain CGU impairment assessments are sensitive to the discount rate applied. Discount rates should reflect the return required by the market and the risks inherent in the cash flows being discounted. There is a risk that management 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.

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 judgemental. There is a risk that material misstatements could arise from unreasonable production forecasts for individually material CGUs and/or from the aggregation of systematic flaws in bp's reserves and resources estimation policies across the OP&O and G&LCE segments.

We identified certain individual CGUs 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 was 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.

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 forecast assumptions such as oil and gas prices, discount rates and reserves estimates, which are inherently judgemental, complex for management to estimate and challenging to audit. Additionally, the magnitude of the potential misstatement risk remains 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 relevant 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 and evaluating 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 29 in Baku during November 2024. 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 assessed management's disclosures in Note 1, 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.
- When performing procedures over specific assets, 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 Note 1, 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 for reasonableness;
- assessed how these policies had been applied to a sample of bp's reserves and resources estimates;
- read and evaluated 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;
- assessed whether management's production forecasts are consistent overall with bp's strategy;
- compared the production forecasts used in the impairment tests with management's approved reserves and resources estimates; and
- performed a retrospective assessment in order to assess management's ability to accurately estimate reserves and resources and to check for indications of estimation bias over time.

2. Decommissioning provisions – Notes 1 and 23 to the financial statements

Critical Audit Matter Description

A decommissioning provision of $11.8 billion is recorded in the financial statements as at 31 December 2024. 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.

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 estimated undiscounted cost of the obligations and the timing of future payments are set out in Note 1 on page 159. 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 the discount rate used in calculating its decommissioning provisions from 4.0% as at 31 December 2023 to 4.5% as at 31 December 2024. The increase was primarily driven by increased US treasury bond rates.

How the Critical Audit Matter was addressed in the Audit

Long term Inflation rate

- We tested the relevant 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 the general long term inflation rate assumption used of 2.0%, comparing it against latest external market data.
- We made inquiries 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 and evaluated 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 evaluate 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 relevant 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 the reasonableness of changes in key cost assumptions, including rig rates, vessel rates, well plug and abandonment duration, and non-productive time 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 disclosure of the estimated undiscounted cost of its obligations and the timing of future decommissioning payments.

Discount rates

- We tested the relevant controls related to the determination of the discount rate assumption.
- We assessed the reasonableness of management's methodology for determining the discount rate and recalculated the discount rate with reference to independent third party data, most notably US treasury bond yields.

3. Valuation of commodity financial derivatives - Notes 1, 29 and 30 to the financial statements

Critical Audit Matter Description

bp's supply, trading and shipping (ST&S) function is responsible for globally trading and risk managing the group's owned as well as third party production. To discharge this responsibility, ST&S regularly executes commodity contracts, physically settled or otherwise, which are accounted for as a derivative and fair valued under IFRS 9. These contracts, therefore, result in unrealised gains/losses that are recognised on account of fair value movements in the associated derivative assets and liabilities.

Determining the fair value of derivative assets and liabilities can be complex and subjective, particularly where the valuation is dependent on significant inputs which are not observable and are classified as level 3 in the fair value hierarchy set out in IFRS 13. This degree of subjectivity also makes such fair value estimates liable to potential fraud by management incorporating bias in the inputs used in determining fair values. Given the significant judgements, sensitivity to management assumptions, and the absolute value associated with these positions, we have identified a risk in respect of certain financial instruments where the valuation is dependent on significant unobservable inputs.

Fair value measurements associated with unrealised commodity contracts are also impacted by the macroeconomic sentiment and outlook. In 2024, commodity markets continued to experience periods of volatility due to continuing uncertainty resulting from the planned energy transition, macro-economic factors such as inflation and interest rates, and disruptions in global supply due to geopolitical conflicts. In response to the volatility observed, we focused our audit efforts on the valuation of commodity derivatives and designed procedures to test for management bias.

As at 31 December 2024, the group's total level 3 derivative financial assets were $16.0 billion and level 3 derivative financial liabilities were $14.4 billion.

How the Critical Audit Matter was addressed in the Audit

To address the complexities associated with auditing the valuation of instruments dependent on significant unobservable inputs, we included valuation specialists with significant quantitative and modelling expertise to assist in performing our audit procedures. Our valuation audit work included the following control and substantive procedures:

- We tested the group's valuation relevant controls including:
  - the model certification control, which is designed to review a model's theoretical soundness and the appropriateness of its valuation methodology; and
  - the 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 valuation testing procedures including:
  - evaluating management's valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period;
  - engaging our valuation specialists to challenge models, develop fair value estimates and evaluate consistency in management's modelling and input assumptions throughout the year;
  - comparing management's input assumptions against the expected assumptions of other market participants and observable market data;
  - independently validating price points on pricing curves to consensus data; and
  - analysing whether there was any indication of management bias through evaluating the distribution of valuation differences where relevant.

4. Impairment of E&A assets and refinery PP&E as a consequence, among other things, of climate change and the energy transition – Notes 1, 4, 8 and 15 to the financial statements

Critical Audit Matter Description

Intangible Assets

The recoverability of certain of the group's $4.4 billion total exploration and appraisal (E&A) assets capitalised as at 31 December 2024 is 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, or lower forecast future oil and gas prices. 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

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 among other things as a consequence of climate change and the energy transition. Management identified impairment indicators in respect of the Gelsenkirchen refinery in Germany during the year and, as a result, an impairment test was performed to assess the recoverability of the Gelsenkirchen refinery carrying value. As disclosed in Note 4 to the accounts on page 166, management has recorded an impairment charge of $0.8 billion in respect of the Gelsenkirchen refinery, primarily driven by changes in economic assumptions. At 31 December 2024 management identified an impairment indicator for all of its other refineries due to a reduction in the local marker margins. The impairment tests performed by management to assess the recoverability of the carrying value of these refineries did not result in any additional impairment charges being recognised.

How the Critical Audit Matter Was Addressed in the Audit

Intangible Assets

In respect of the recoverability of E&A assets capitalised as at 31 December 2024:

- We tested the relevant controls within the group's E&A write-off and impairment assessment processes; and
- We challenged and evaluated management's key E&A judgements with regards to the impairment criteria of IFRS 6. Where impairment indicators were identified 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 assessing licence documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms.

PP&E

We considered the impact of potential changes in supply and demand on the group's refining portfolio and assessed internal and external market studies of future supply and demand. In relation to refinery impairment tests performed by management, our audit procedures included:

- Evaluating the valuation methodology and testing the integrity and mechanical accuracy of the impairment models;
- Assessing the appropriateness of key assumptions and inputs to the impairment models, notably forecast refining margins, discount rate and energy input costs, challenging and evaluating management's assumptions by reference to third party data where available and involvement of our valuation specialists; and
- Evaluating management's ability to forecast future cash flows and margins by comparing actual results with historical forecasts and tested management's internal controls over the impairment test and related inputs.

/s/ Deloitte LLP

London
United Kingdom
6 March 2025

We have served as bp's auditor since 2018.

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.

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 2024, 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 2024, 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 2024, of the group and our report dated 6 March 2025 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 bp bioenergy (formerly called Bunge Bioenergia) and Lightsource bp which were acquired on 1 October 2024, and 24 October 2024, respectively. bp bioenergy financial statement line items comprise 2.1% and 0.9% of net and total assets respectively, 0.3% of sales and other operating revenues, and (4.5)% of profit (loss) for the year of the consolidated financial statement amounts as of and for the year ended 31 December 2024. Lightsource bp's financial statement line items comprise 6.3% and 2.4% of net and total assets respectively, 0.1% of sales and other operating revenues, and (5.7)% of profit (loss) for the year of the consolidated financial statement amounts as of and for the year ended 31 December 2024. Accordingly, our audit did not include the internal control over financial reporting at bp bioenergy and Lightsource bp.

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
6 March 2025

Group income statement

For the year ended 31 December				$ million
	Note	**2024**	2023	2022
Sales and other operating revenues	6	**189,185**	210,130	241,392
Earnings from joint ventures – after interest and tax	16	**909**	67	1,128
Earnings from associates – after interest and tax	17	**1,084**	831	1,402
Interest and other income	7	**2,773**	1,635	1,103
Gains on sale of businesses and fixed assets	4	**678**	369	3,866
Total revenues and other income		**194,629**	213,032	248,891
Purchases	19	**113,941**	119,307	141,043
Production and manufacturing expenses		**26,584**	25,044	28,610
Production and similar taxes	5	**1,799**	1,779	2,325
Depreciation, depletion and amortization	5	**16,622**	15,928	14,318
Net impairment and losses on sale of businesses and fixed assets	4	**6,995**	5,857	30,522
Exploration expense	8	**974**	997	585
Distribution and administration expenses		**16,417**	16,772	13,449
Profit (loss) before interest and taxation		**11,297**	27,348	18,039
Finance costs	7	**4,683**	3,840	2,703
Net finance (income) expense relating to pensions and other post-employment benefits	24	**(168)**	(241)	(69)
Profit (loss) before taxation		**6,782**	23,749	15,405
Taxation	9	**5,553**	7,869	16,762
Profit (loss) for the year		**1,229**	15,880	(1,357)
Attributable to				
bp shareholders		**381**	15,239	(2,487)
Non-controlling interests		**848**	641	1,130
		1,229	15,880	(1,357)
Earnings per share				
Profit (loss) for the year attributable to bp shareholders				
Per ordinary share (cents)				
Basic	11	**2.38**	87.78	(13.10)
Diluted	11	**2.32**	85.85	(13.10)
Per ADS (dollars)				
Basic	11	**0.14**	5.27	(0.79)
Diluted	11	**0.14**	5.15	(0.79)

Group statement of comprehensive income

For the year ended 31 December				$ million
	Note	**2024**	2023	2022
Profit (loss) for the year		**1,229**	15,880	(1,357)
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences[a]		**(1,292)**	585	(3,786)
Exchange (gains) losses on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets[a]		**1,004**	(2)	10,759
Cash flow hedges marked to market	30	**155**	1,065	(825)
Cash flow hedges reclassified to the income statement	30	**(686)**	(428)	1,502
Costs of hedging marked to market	30	**(2)**	(67)	61
Costs of hedging reclassified to the income statement	30	**(2)**	(11)	25
Share of items relating to equity-accounted entities, net of tax	16, 17	**(12)**	(192)	402
Income tax relating to items that may be reclassified	9	**48**	(10)	(334)
		(787)	940	7,804
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-employment benefit liability or asset	24	**(360)**	(2,262)	340
Remeasurements of equity investments		**(47)**	51	—
Cash flow hedges that will subsequently be transferred to the balance sheet	30	**(1)**	15	(4)
Income tax relating to items that will not be reclassified[a]	9	**734**	745	68
		326	(1,451)	404
Other comprehensive income		**(461)**	(511)	8,208
Total comprehensive income		**768**	15,369	6,851
Attributable to				
bp shareholders		**7**	14,702	5,782
Non-controlling interests		**761**	667	1,069
		768	15,369	6,851

a See Note 32 for further information.

Group statement of changes in equity[a]

$ million

	Share capital and capital reserves	Treasury shares	Foreign currency translation reserve	Fair value reserves	Profit and loss account	bp shareholders' equity	Non-controlling interests Hybrid bonds	Non-controlling interests Other interest	Total equity
At 1 January 2024	**48,013**	**(11,323)**	**(1,920)**	**174**	**35,339**	**70,283**	**13,566**	**1,644**	**85,493**
Profit for the year	**–**	**–**	**–**	**–**	**381**	**381**	**641**	**207**	**1,229**
Other comprehensive income	**–**	**–**	**(276)**	**(452)**	**354**	**(374)**	**–**	**(87)**	**(461)**
Total comprehensive income	**–**	**–**	**(276)**	**(452)**	**735**	**7**	**641**	**120**	**768**
Dividends[b]	**–**	**–**	**–**	**–**	**(5,018)**	**(5,018)**	**–**	**(375)**	**(5,393)**
Cash flow hedges transferred to the balance sheet, net of tax	**–**	**–**	**–**	**(10)**	**–**	**(10)**	**–**	**–**	**(10)**
Repurchase of ordinary share capital	**–**	**–**	**–**	**–**	**(7,302)**	**(7,302)**	**–**	**–**	**(7,302)**
Share-based payments, net of tax	**216**	**2,293**	**–**	**–**	**(1,426)**	**1,083**	**–**	**–**	**1,083**
Issue of perpetual hybrid bonds	**–**	**–**	**–**	**–**	**(22)**	**(22)**	**4,352**	**–**	**4,330**
Redemption of perpetual hybrid bonds, net of tax	**–**	**–**	**–**	**–**	**9**	**9**	**(1,300)**	**–**	**(1,291)**
Payments on perpetual hybrid bonds	**–**	**–**	**–**	**–**	**–**	**–**	**(610)**	**–**	**(610)**
Transactions involving non-controlling interests, net of tax	**–**	**–**	**–**	**–**	**216**	**216**	**–**	**1,034**	**1,250**
At 31 December 2024	**48,229**	**(9,030)**	**(2,196)**	**(288)**	**22,531**	**59,246**	**16,649**	**2,423**	**78,318**
At 1 January 2023	47,873	(12,153)	(2,643)	(256)	34,732	67,553	13,390	2,047	82,990
Profit for the year	–	–	–	–	15,239	15,239	586	55	15,880
Other comprehensive income	–	–	728	431	(1,696)	(537)	–	26	(511)
Total comprehensive income	–	–	728	431	13,543	14,702	586	81	15,369
Dividends[b]	–	–	–	–	(4,831)	(4,831)	–	(403)	(5,234)
Cash flow hedges transferred to the balance sheet, net of tax	–	–	–	(1)	–	(1)	–	–	(1)
Repurchase of ordinary share capital	–	–	–	–	(8,167)	(8,167)	–	–	(8,167)
Share-based payments, net of tax	140	830	–	–	(301)	669	–	–	669
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	1	1	–	–	1
Issue of perpetual hybrid bonds	–	–	–	–	(1)	(1)	176	–	175
Payments on perpetual hybrid bonds	–	–	(5)	–	–	(5)	(586)	–	(591)
Transactions involving non-controlling interests, net of tax	–	–	–	–	363	363	–	(81)	282
At 31 December 2023	48,013	(11,323)	(1,920)	174	35,339	70,283	13,566	1,644	85,493
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
Issue of perpetual hybrid bonds	–	–	–	–	(4)	(4)	374	–	370
Payments on perpetual hybrid bonds	–	–	15	–	–	15	(544)	–	(529)
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

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

Group balance sheet

At 31 December			$ million
	Note	2024	2023
Non-current assets			
Property, plant and equipment	12	**100,238**	104,719
Goodwill	14	**14,888**	12,472
Intangible assets	15	**9,646**	9,991
Investments in joint ventures	16	**12,291**	12,435
Investments in associates	17	**7,741**	7,814
Other investments	18	**1,292**	2,189
Fixed assets		**146,096**	149,620
Loans		**1,961**	1,942
Trade and other receivables	20	**1,815**	1,767
Derivative financial instruments	30	**16,114**	9,980
Prepayments		**548**	623
Deferred tax assets	9	**5,403**	4,268
Defined benefit pension plan surpluses	24	**7,457**	7,948
		179,394	176,148
Current assets			
Loans		**223**	240
Inventories	19	**23,232**	22,819
Trade and other receivables	20	**27,127**	31,123
Derivative financial instruments	30	**5,112**	12,583
Prepayments		**2,594**	2,520
Current tax receivable		**1,096**	837
Other investments	18	**165**	843
Cash and cash equivalents	25	**39,204**	33,030
		98,753	103,995
Assets classified as held for sale	2	**4,081**	151
		102,834	104,146
Total assets		**282,228**	280,294
Current liabilities			
Trade and other payables	22	**58,411**	61,155
Derivative financial instruments	30	**4,347**	5,250
Accruals		**6,071**	6,527
Lease liabilities	28	**2,660**	2,650
Finance debt	26	**4,474**	3,284
Current tax payable		**1,573**	2,732
Provisions	23	**3,600**	4,418
		81,136	86,016
Liabilities directly associated with assets classified as held for sale	2	**1,105**	62
		82,241	86,078
Non-current liabilities			
Other payables	22	**9,409**	10,076
Derivative financial instruments	30	**18,532**	10,402
Accruals		**1,326**	1,310
Lease liabilities	28	**9,340**	8,471
Finance debt	26	**55,073**	48,670
Deferred tax liabilities	9	**8,428**	9,617
Provisions	23	**14,688**	14,721
Defined benefit pension plan and other post-employment benefit plan deficits	24	**4,873**	5,456
		121,669	108,723
Total liabilities		**203,910**	194,801
Net assets		**78,318**	85,493
Equity			
bp shareholders' equity	32	**59,246**	70,283
Non-controlling interests	32	**19,072**	15,210
Total equity	32	**78,318**	85,493

Helge Lund Chair
Murray Auchincloss Chief executive officer
6 March 2025

Group cash flow statement

For the year ended 31 December				$ million
	Note	**2024**	2023	2022
Operating activities				
Profit (loss) before taxation		**6,782**	23,749	15,405
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	8	**767**	746	385
Depreciation, depletion and amortization	5	**16,622**	15,928	14,318
Impairment and (gain) loss on sale of businesses and fixed assets	4	**6,317**	5,488	26,656
Earnings from joint ventures and associates		**(1,993)**	(898)	(2,530)
Dividends received from joint ventures and associates		**2,023**	2,092	1,700
Remeasurement of joint ventures	3	**(917)**	—	—
Interest receivable		**(1,512)**	(1,265)	(444)
Interest received		**1,450**	1,119	414
Finance costs	7	**4,683**	3,840	2,703
Interest paid		**(2,811)**	(2,950)	(2,208)
Net finance expense relating to pensions and other post-employment benefits	24	**(168)**	(241)	(69)
Share-based payments		**1,174**	616	795
Net operating charge for pensions and other post-employment benefits, less contributions and benefit payments for unfunded plans	24	**(182)**	(193)	(257)
Net charge for provisions, less payments		**(152)**	(2,481)	440
(Increase) decrease in inventories		**808**	5,634	(5,492)
(Increase) decrease in other current and non-current assets		**3,355**	4,620	(18,584)
Increase (decrease) in other current and non-current liabilities		**(188)**	(13,592)	17,806
Income taxes paid		**(8,761)**	(10,173)	(10,106)
Net cash provided by operating activities		**27,297**	32,039	40,932
Investing activities				
Expenditure on property, plant and equipment, intangible and other assets		**(15,297)**	(14,285)	(12,069)
Acquisitions, net of cash acquired	3	**53**	(799)	(3,530)
Investment in joint ventures		**(850)**	(1,039)	(600)
Investment in associates		**(143)**	(130)	(131)
Total cash capital expenditure		**(16,237)**	(16,253)	(16,330)
Proceeds from disposals of fixed assets	4	**328**	133	709
Proceeds from disposals of businesses, net of cash disposed	4	**2,578**	1,193	1,841
Proceeds from loan repayments		**81**	55	67
Net cash used in investing activities		**(13,250)**	(14,872)	(13,713)
Financing activities				
Repurchase of shares		**(7,127)**	(7,918)	(9,996)
Lease liability payments		**(2,833)**	(2,560)	(1,961)
Proceeds from long-term financing		**10,656**	7,568	2,013
Repayments of long-term financing		**(2,970)**	(3,902)	(11,697)
Net increase (decrease) in short-term debt		**(2,966)**	(861)	(1,392)
Issue of perpetual hybrid bonds		**4,330**	175	370
Redemption of perpetual hybrid bonds	32	**(1,288)**	—	—
Payments relating to perpetual hybrid bonds		**(1,053)**	(1,008)	(708)
Payments relating to transactions involving non-controlling interests (other)		**(21)**	(187)	(9)
Receipts relating to transactions involving non-controlling interests (other)		**1,353**	546	11
Dividends paid				
bp shareholders	10	**(5,003)**	(4,809)	(4,358)
Non-controlling interests		**(375)**	(403)	(294)
Net cash provided by (used in) financing activities		**(7,297)**	(13,359)	(28,021)
Currency translation differences relating to cash and cash equivalents		**(511)**	27	(684)
Increase (decrease) in cash and cash equivalents		**6,239**	3,835	(1,486)
Cash and cash equivalents at beginning of year		**33,030**	29,195	30,681
Cash and cash equivalents at end of year[a]		**39,269**	33,030	29,195

a 2024 includes cash and cash equivalents classified as assets held for sale in the group balance sheet. See Note 2 for further information.

Notes on financial statements

1. Material accounting policy information, significant 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) were approved and signed by the chief executive officer and chairman on 6 March 2025 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 IFRS Accounting 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 material accounting policy information 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 IFRSs and IFRS Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2024. 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.

Material accounting policy information: use of judgements, estimates and assumptions

Inherent in the application of many of the accounting policies used in preparing the consolidated financial statements is the need for bp management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. Actual outcomes could differ from the estimates and assumptions used. The accounting judgements and estimates that have a significant impact on the results of the group are set out in boxed text below, and should be read in conjunction with the information provided in the Notes on financial statements.

The areas requiring the most significant judgement and estimation in the preparation of the consolidated financial statements are: accounting for the investments in Rosneft and Aker BP; exploration and appraisal intangible assets; the recoverability of asset carrying values, including the estimation of reserves; supplier financing arrangements; derivative financial instruments; provisions and contingencies; pensions and other post-employment 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 20) 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. The assumptions for future carbon emissions costs in value-in-use impairment testing differ from the investment appraisal assumptions and are described below.

Management has also not identified any off-balance sheet commodity purchase obligations to be onerous contracts as result of the transition to a lower carbon economy at 31 December 2024.

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 2024. The revised price assumptions have been rebased in real 2023 terms and are materially consistent with the disclosed prices in real 2022 terms. The near term Brent oil assumption was held constant at $70 per barrel to reflect near-term supply constraints before declining after 2030 to $50 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 2050 were held constant at $4.00 per mmBtu reflecting an assumption that declining domestic demand in the US is offset by higher LNG exports. The revised assumptions for Brent oil and Henry Hub gas 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.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

As noted above, the group's investment appraisal process includes a carbon emissions price series for the investment economics which is applied to bp's anticipated share of bp's forecast of the investment assets' scope 1 and 2 GHG emissions where they exceed defined thresholds, and is assumed to apply whether or not bp is the asset 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. A key input into the determination of impairment is the assumption, aligned with bp's aim to reach net zero greenhouse gas emissions by 2050 or sooner, that the current recognized portfolio of oil and gas properties and refining assets will have an immaterial carrying value by 2050.

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 the 2024 value-in-use impairment tests is for the UK North Sea and the Gelsenkirchen refinery. The assumptions for UK North Sea were £59/tCO_2e in 2025 gradually increasing to £231/tCO_2e in 2050. The assumption applied for the Gelsenkirchen refinery was an average of approximately $97/t$CO_2$e.

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 realized 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. 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.

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. The recoverability of the group's exploration and appraisal intangible assets was considered during 2024. 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 have immaterial carrying values within the next 12 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 2024 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 material accounting policy: property, plant and equipment for more information.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

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. 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 cost assumptions 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 does not expect manufacturing to cease at refineries within a determinate period of time, as existing property, plant and equipment is expected to be renewed or replaced. Management will continue to review facts and circumstances, including where cessation of manufacturing decisions have been made, to assess if decommissioning provisions need to be recognized. Decommissioning provisions relating to refineries at 31 December 2024 are not material. See significant judgements and estimates: provisions for further information.

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

Oil and gas price assumptions applied in value-in-use impairment testing have been updated for inflation and have been rebased in real 2023 terms. 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 during the year to reflect higher US Treasury yields. The principal impact of this rate increase was a $0.9 billion decrease in the decommissioning provision with an associated decrease in the carrying amount of property, plant and equipment of $0.7 billion and a pre-tax credit to the income statement of $0.2 billion. The post-tax impairment discount rate applicable to assets other than renewable power assets remained consistent with 2023 as did the risk premium applied to the majority of countries classified as higher-risk. See significant judgements and estimates: recoverability of asset carrying values and provisions for further information.

Pensions and other post-employment benefits

The volatility in the financial markets during 2024 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-employment benefits and Note 24 for further information.

Basis of consolidation

The group financial statements consolidate the financial statements of BP p.l.c. and its subsidiaries drawn up to 31 December each year. Subsidiaries are consolidated from the date of their acquisition, being the date on which the group obtains control, 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.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

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 revenue 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.

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 has significant influence over Aker BP, a Norwegian oil and gas company, is significant.

As a consequence of this judgement, bp uses the equity method of accounting for its investment and bp's share of 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.

bp owned 15.9% of the voting shares at 31 December 2024. bp's senior vice president North Sea, Doris Reiter, was appointed a member of the Aker BP board during 2024. bp's other nominated director, group chief financial officer, 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 continues to have significant influence at 31 December 2024.

Significant judgements and estimate: investment in Rosneft

Since the first quarter 2022, bp accounts for its interest in Rosneft and its other businesses with Rosneft within Russia, as financial assets measured at fair value within 'Other investments'. 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. It is considered by management that any measure of fair value, other than nil, would be subject to such high measurement uncertainty, considering the sanctions and restrictions implemented by Russia on Russian assets held by foreign investors, 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 zero when determining the measurement of the interest in Rosneft and the other businesses with Rosneft within Russia as at 31 December 2024. Events or outcomes within the next financial year, that are different to those outlined above, could materially change the fair value of the investment.

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 and its other businesses with Rosneft within Russia, for the years to 31 December 2022, 31 December 2023 and 31 December 2024 have not been met.

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. Material accounting policy information, significant 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.

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. Material accounting policy information, significant 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.

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 223, which is unaudited. Details on bp’s proved reserves and production compliance and governance processes are provided on page 322. The 2024 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 223.

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

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

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 discount rates, 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.

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 2024 relating to discount rates and oil and gas properties are discussed below. Changes in the economic environment including as a result of the energy transition or other facts and circumstances may necessitate revisions to these assumptions and could result in a material change to the carrying values of the group's assets within the next financial year.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Discount rates

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the CGU. Value-in-use calculations are typically discounted using a pre-tax discount rate based upon the cost of funding the group derived from an established model, adjusted to a pre-tax basis and incorporating a market participant capital structure and country risk premiums. Fair value less costs of disposal discounted cash flow calculations use a post-tax discount rate.

The discount rates applied in impairment tests are reassessed each year and, in 2024, the post-tax discount rate was 8% (2023 8%) other than for renewable power assets. Where the CGU is located in a country that was judged to be higher risk, an additional premium of 1% to 3% was reflected in the post-tax discount rate (2023 1% to 4%). The judgement of classifying a country as higher risk and the applicable premium takes into account various economic and geopolitical factors. The pre-tax discount rate, other than for renewable power assets, typically ranged from 9% to 20% (2023 9% to 20%) depending on the risk premium and applicable tax rate in the geographic location of the CGU. For renewable power assets, which were tested primarily on a fair-value basis in 2024 (including those in equity accounted entities) tests were performed using a post-tax cost of equity-based discount rate range of 8.75% to 9.5%. In 2023, tests were performed on a value-in-use basis using a post-tax WACC-based discount rate of 6.5%.

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 2024, the group identified oil and gas properties in these segments with carrying amounts totalling $17,853 million (2023 $18,374 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 145. 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 were revised. The revised price assumptions have been rebased in real 2023 terms and are materially consistent with the disclosed prices in real 2022 terms. The near term Brent oil assumption was held constant at $70 per barrel to reflect near term supply constraints before declining after 2030 to $50 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 2050 were held constant at $4.00 per mmBtu reflecting an assumption that declining domestic demand in the US is offset by higher LNG exports. These price assumptions are derived from the central case investment appraisal assumptions (see page 20). A summary of the group's revised price assumptions for Brent oil and Henry Hub gas, applied in 2024 and 2023, in real 2023 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. Inflation rate of 2% - 2.5% (2023 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 12 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.

2024 price assumptions		**2025**	**2030**	**2040**	**2050**
Brent oil ($/bbl)		70	70	63	50
Henry Hub gas ($/mmBtu)		4.00	4.00	4.00	4.00

2023 price assumptions	**2024**	**2025**	**2030**	**2040**	**2050**
Brent oil ($/bbl)	71	71	71	59	46
Henry Hub gas ($/mmBtu)	4.06	4.05	4.05	4.05	4.05

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Global oil production increased by 1.4% in 2024 with this growth predominantly coming from non-OPEC countries as OPEC+ continued its output reductions. Global oil demand growth slowed, increasing by 0.9% in 2024 as we leave the post-Covid recovery period and Chinese demand fell short of forecasts. Brent dropped by nearly $2 per barrel in 2024 in response to lacklustre demand growth and increasing supply. While geopolitical risk (e.g., tariffs, sanctions) may support prices in the short-term, bp's long-term assumption for oil prices is lower than the 2024 average as oil demand is likely to fall such that the price levels needed to encourage sufficient investment to meet global oil demand will also be lower.

US Henry Hub spot prices averaged $2.2/mmBtu in 2024 from $2.5/mmBtu in 2023. Prices fell further in order to reduce output and stimulate demand in the power sector. Milder than normal winter weather during winter 2023/2024 left US gas storage levels over 20% above historic average levels at the end of winter 2023/2024, causing prices to fall below $2/mmBtu. Meanwhile, after growing by 4 Bcf/d in 2023, low prices caused natural gas production to fall by 0.4 Bcf/d in 2024, helping to bring the market back into balance. The level of US gas prices in 2024 was below bp’s long term price assumption based on the judgment 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 8% in all years up to 2040, and 25% in all remaining years to 2050; and a decrease in net revenues of 20% in all years up to 2030, 35% in all subsequent years to 2040 and 50% 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 $19-20 billion which is approximately 30% of the associated net book value of property, plant and equipment as at 31 December 2024. 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 42).

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 2-3% of the associated net book value of property, plant and equipment as at 31 December 2024. This potential increase in the carrying amount would arise due to reversals of previously recognized impairments and represents approximately one fifth of the total impairment reversal capacity available at 31 December 2024. 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.

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 loss recognized in 2024 would have been approximately $0.2 billion higher. If the discount rate was one percentage point lower, the net impairment loss recognized would have been approximately $0.5 billion lower.

Management considers refining margins to be the key source of estimation uncertainty in determining the recoverable amount of refinery assets. The sensitivity analysis below, in addition to covering the key sources of estimation uncertainty, also indicates how the energy transition and/or reduced demand for refined products may further impact forecast cash inflows to a greater extent than currently anticipated in the group's value-in-use estimates for refinery CGUs.

Management tested the impact of a $1/barrel decrease in each refinery's future margin assumption in all years of the value-in-use estimate. A reduction of this magnitude in isolation could indicatively lead to a reduction in the carrying amount of bp's currently held refining property, plant and equipment in the range of $1-2 billion.

This sensitivity analysis does not, however, represent management's best estimate of any impairment charges that might be recognized as it does not fully incorporate consequential changes that may arise, such as changes in costs and business plans and crude or product slates. The above sensitivity analysis therefore does not reflect a linear relationship between margins and value that can be extrapolated. The interdependency of these inputs and factors plus the varying configurations of the group's refineries limits the practicability of estimating the probability or extent to which the overall recoverable amount is impacted by changes to the margin assumptions.

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 $14.9 billion on its balance sheet (2023 $12.5 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy, Reliance and Lightsource bp transactions. Of this, $7.2 billion relates to goodwill in the oil production & operations segment and to hydrocarbon CGUs within the gas & low carbon energy segment (2023 $7.0 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 material accounting policy information: 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. Material accounting policy information, significant 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 held for the purpose of meeting short-term cash commitments and 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. Material accounting policy information, significant 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 financing arrangements that utilize letter of credit facilities, promissory notes and reverse factoring. Judgement is required to assess the payables subject to these arrangements to determine whether they should continue to be classified as trade payables and give rise to operating cash flows or finance debt and financing cash flows. The criteria used in making this assessment include the payment terms for the amount due relative to terms commonly seen in the markets in which bp operates and whether the arrangements significantly change the nature of the liability. Liabilities subject to these arrangements with payment terms of up to approximately 60 days are generally considered to be trade payables and give rise to operating cash flows. See Note 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. Material accounting policy information, significant 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 probable 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 4.5% (2023 4%).

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. Material accounting policy information, significant 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 trading and shipping 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. Material accounting policy information, significant 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 $0.7 billion of decommissioning provisions recognized as at 31 December 2024 (2023 $0.6 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 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 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 is not yet expected within a determinate time period, as existing property plant and equipment is expected to be renewed or replaced.

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 2024 was 4.5% (2023 4%), which was based on long-dated US government bonds interpolated to reflect the expected weighted average time to decommissioning. The weighted average period over which decommissioning and environmental costs are generally expected to be incurred is estimated to be approximately 17 years (2023 17 years) and 7 years (2023 6 years) respectively. Costs at future prices are typically determined by applying an inflation rate of 1.5% (2023 1.5%) to decommissioning costs and 2% (2023 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 $5.5 billion (2023 $5.5 billion) within the next 10 years, $6.2 billion (2023 $5.8 billion) in 10 to 20 years and the remainder of approximately $6.7 billion (2023 $6.6 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 $1.5 billion (2023 $1.6 billion). The pre-tax impact on the group income statement would be a credit of approximately $0.4 billion (2023 $0.4 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 $0.3 billion (2023 $0.6 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 (2023 $1.1 billion) and a pre-tax charge of approximately $0.4 billion (2023 $0.2 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 $1.7 billion (2023 $1.9 billion) with a pre-tax charge of approximately $0.5 billion (2023 $0.5 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 material accounting policy information for pensions and other post-employment benefits are described below.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Pensions and other post-employment 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-employment 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-employment benefits

Accounting for defined benefit pensions and other post-employment 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-employment 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-employment 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-employment benefit obligations within the next financial year. 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.

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.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

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

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

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

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

In addition, the group has carry-forward tax losses and tax credits in certain taxing jurisdictions that are available to offset against future taxable profit. However, deferred tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused tax losses or tax credits can be utilized. Management judgement is exercised in assessing whether this is the case and estimates are required to be made of the amount of future taxable profits that will be available. Such judgements are inherently impacted by estimates affecting future taxable profits such as oil and natural gas prices and decommissioning expenditure, see 'Significant judgements and estimates: recoverability of asset carrying values and provisions'.

In July 2023, the UK government enacted legislation to implement the Pillar Two Model rules. The legislation is effective for bp from 1 January 2024 and includes an income inclusion rule and a domestic minimum tax, which together are designed to ensure a minimum effective tax rate of 15% in each country in which the group operates. Similar legislation is being enacted by other governments around the world. In line with the amendments to IAS 12, the exception from recognising and disclosing information about deferred tax assets and liabilities related to Pillar Two income taxes has been applied.

In October 2024, the UK government announced changes (effective from 1 November 2024) to the Energy Profits Levy including a 3% increase in the rate taking the headline rate of tax on North Sea profits to 78%, an extension to the period of application of the Levy to 31 March 2030 and the removal of the Levy's main investment allowance. The changes to the rate and to the investment allowance were substantively enacted in 2024 and have been applied in accounting for current tax and deferred tax in the year, resulting in an additional non-cash deferred tax charge of approximately $0.1 billion. The extension of the Levy to 31 March 2030 was substantively enacted after 31 December 2024 and will result in a non-cash deferred tax charge of around $0.5 billion in the year ended 31 December 2025.

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.

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. Instead, the nominal amount is transferred to the capital redemption reserve and any difference to the purchase price is shown as a deduction from the profit and loss account reserve in the group statement of changes in equity.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Revenue and other income

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

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

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

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.

Sales and other transactions through which the group loses control of solar projects developed under Lightsource bp's develop-to-sell business model are accounted for as revenues from contracts with customers.

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 material accounting policy information

Impact of new International Financial Reporting Standards

Amendments to IAS 7 ' Statement of Cash Flows' and IFRS 7 'Financial Instruments: disclosures' relating to supplier finance have been adopted for the consolidated financial statements for 2024, the additional required disclosures are provided in the Liquidity risk section of Note 29.

There are no new or other amended standards or interpretations adopted from 1 January 2024 onwards, that have a significant impact on the consolidated financial statements for 2024.

Not yet adopted

Amendments to IFRS 9 ' Financial Instruments' relating to the settlement of liabilities through electronic payment systems are effective for annual periods beginning on or after 1 January 2026 subject to endorsement by the UK Endorsement Board. The potential impact on cash and banking operations and amounts reported in cash and cash equivalents on adoption of the amendments is currently being assessed.

IFRS 18 'Presentation and Disclosure in Financial Statements' will supersede IAS 1 'Presentation of Financial Statements' and is effective for annual periods beginning on or after 1 January 2027 subject to endorsement by the UK Endorsement Board. IFRS 18 (and consequential amendments made to IAS 7 'Statement of Cash Flows', IAS 8 'Accounting Policies: Changes in Accounting Estimates and Errors', IAS 33 'Earnings per share' and IFRS 7 'Financial Instruments: Disclosures') introduces several new requirements that are expected to impact the presentation and disclosure of the Group's consolidated financial statements. These new requirements include:

- Requirements to classify all income and expenses included in the statement of profit or loss into one of five categories and to present two new mandatory subtotals.
- Requirement to use the operating profit subtotal as the starting point for the indirect method of reporting cash flows from operating activities in the statement of cash flows.
- Specific classification requirements for interest paid/received and dividends received in the statement of cash flows such that interest and dividend receipts are included as investing cash flows and interest paid as financing cash flows.
- Required disclosures about certain non-GAAP measures ('management defined performance measures') in a single note to the financial statements
- Enhanced guidance on the aggregation of information across all the primary financial statements and the notes.

The group's evaluation of the effect of adopting IFRS 18 is ongoing but it is currently anticipated that IFRS 18 will have a significant impact on the presentation of the Group's financial statements and related disclosures.

2. Non-current assets held for sale

The carrying amount of assets classified as held for sale at 31 December 2024 is $4,081 million (2023 $151 million), with associated liabilities of $1,105 million (2023 $62 million).

gas & low carbon energy

On 16 September 2024, bp announced that it plans to sell its US onshore wind energy business, bp Wind Energy. bp Wind Energy has interests in ten operating onshore wind energy assets across seven US states. As a result of progression of the disposal process during the fourth quarter of 2024, completion of a disposal in 2025 is now considered to be highly probable. The carrying amount of assets classified as held for sale at 31 December 2024 is $569 million, with associated liabilities of $41 million.

On 24 October, bp completed the acquisition of the remaining 50.03% of Lightsource bp. The acquisition included certain assets for which sales processes were in progress at the acquisition date. Completion of the sale of these assets within one year of the acquisition date is considered to be highly probable. The carrying amount of assets classified as held for sale at 31 December 2024 is $1,702 million, with associated liabilities of $1,050 million.

On 9 December 2024, bp and JERA Co., Inc. agreed to combine their offshore wind businesses to form a new standalone, equally-owned joint venture – JERA Nex bp. The parties have agreed to work to complete formation of JERA Nex bp, subject to regulatory and other approvals, by end of the third quarter of 2025. bp will contribute its development projects in the UK, Japan, Germany and US into the new joint venture. The related assets and liabilities of those projects have, therefore, been classified as held for sale. The carrying amount of assets classified as held for sale at 31 December 2024 is $1,793 million, with associated liabilities of $14 million.

Transactions that have been classified as held for sale during 2024, but were completed by 31 December 2024, are described below.

gas & low carbon energy

On 14 February 2024, bp and ADNOC announced that they had agreed to form a new joint venture (JV) in Egypt. On 16 December bp and XRG (ADNOC's international energy investment company) announced they had completed formation of Arcius Energy (51% bp, 49% XRG, ADNOC's international energy investment company). As part of the agreement, bp contributed its interests in three development concessions, as well as exploration agreements, in Egypt to the new JV. XRG made a proportionate cash contribution.

oil production & operations

On 4 October 2024, bp completed the sale of receivables relating to a prior divestment receiving proceeds of $890 million.

customers & products

At 31 December 2023 assets of $151 million and associated liabilities of $62 million were classified as held for sale relating to the sale of bp's Türkiye ground fuels business to Petrol Ofisi. This included the group's interest in three joint venture terminals in Türkiye. The sale completed on 31 October 2024 and resulted in a loss on disposal of $1,132 million including recycling of cumulative foreign exchange losses from reserves of $942 million.

The total assets and liabilities held for sale at 31 December 2024 and 2023, which are in the gas & low carbon energy and customers & products segments, are set out in the table below.

		$ million
	2024	2023
Property, plant and equipment	**1,981**	49
Intangible assets	**333**	3
Investments in joint ventures	**1,182**	—
Loans	**—**	1
Cash	**65**	—
Trade and other receivables	**520**	98
Assets classified as held for sale	**4,081**	151
Trade and other payables	**(264)**	(1)
Lease liabilities	**(58)**	(40)
Finance debt	**(720)**	—
Provisions	**(63)**	(10)
Defined benefit pension plan and other post-employment benefit plan deficits	**—**	(11)
Liabilities directly associated with assets classified as held for sale	**(1,105)**	(62)

3. Business combinations and other significant transactions

Business combinations

2024

The group undertook a number of business combinations during 2024. Total consideration was $2,119 million and the amount paid in cash in 2024 amounted to $978 million offset by cash acquired of $1,031 million.

These business combinations principally relate to the step acquisitions of bp Bunge Bioenergia and Lightsource bp. Total consideration for these two acquisitions was $1,328 million and the amount paid in cash in 2024 was $227 million, offset by cash acquired of $589 million. The provisional fair value of the net assets (including goodwill) recognized from these business combinations for 2024 was $2,848 million.

The gain recognized in 'Interest and other income' in 2024 as a result of remeasuring the previously held interests in bp Bunge Bioenergia and Lightsource bp, to fair value, was $427 million.

Immediately prior to the Lightsource bp business combination, certain assets in the US were transferred from Lightsource bp into a new joint venture which remains jointly controlled by bp and certain founder shareholders of Lightsource bp, and is accordingly equity accounted for by bp. The investment in the new joint venture was measured at bp's share of the joint venture's net assets and, as a result, income of $498 million has been recognized in 'Interest and other income' in 2024.

Business combinations

2023

The group undertook a number of business combinations during 2023. Total consideration paid in cash amounted to $1,282 million, offset by cash acquired of $484 million.

The fair value of the net assets (including goodwill) recognized from business combinations in the full year, inclusive of measurement period adjustments for business combinations in previous periods, was $1,228 million. This principally related to the acquisition of TravelCenters of America.

4. Disposals and impairment

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

			$ million
	2024	2023	2022
Gains on sale of businesses and fixed assets			
gas & low carbon energy	**297**	19	45
oil production & operations	**144**	297	3,446
customers & products	**190**	44	374
other businesses & corporate	**47**	9	1
	678	369	3,866

			$ million
	2024	2023	2022
Losses on sale of businesses and fixed assets, and closures			
gas & low carbon energy	**303**	9	—
oil production & operations	**19**	5	921
customers & products	**1,457**	143	177
other businesses & corporate	**27**	(1)	11,083
	1,806	156	12,181
Impairment losses			
gas & low carbon energy	**2,793**	2,213	745
oil production & operations	**1,155**	1,840	4,480
customers & products	**1,661**	1,614	1,874
other businesses & corporate	**24**	80	13,536
	5,633	5,747	20,635
Impairment reversals			
gas & low carbon energy	**(44)**	(1)	(1,333)
oil production & operations	**(384)**	(26)	(893)
customers & products	**(1)**	—	(68)
other businesses & corporate	**(15)**	(19)	—
	(444)	(46)	(2,294)
Impairment and losses on sale of businesses and fixed assets, and closures	**6,995**	5,857	30,522

4. Disposals and impairment – continued

Disposals

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

			$ million
	2024	2023	2022
Proceeds from disposals of fixed assets	**328**	133	709
Proceeds from disposals of businesses, net of cash disposed	**2,578**	1,193	1,841
	2,906	1,326	2,550
By business			
gas & low carbon energy	**840**	536	22
oil production & operations	**1,699**	333	1,935
customers & products	**291**	436	592
other businesses & corporate	**76**	21	1
	2,906	1,326	2,550

Proceeds from disposals of businesses in 2024 includes $594 million relating to the formation of a new joint venture, Arcius Energy, in Egypt, as well as $1,331 million relating to Alaska and $252 million relating to Canada, both prior period disposals. At 31 December 2024, deferred consideration relating to disposals amounted to $112 million receivable within one year (2023 $141 million and 2022 $191 million) and $244 million receivable after one year (2023 $217 million and 2022 $194 million). The amounts of deferred consideration are reported within Trade and other receivables in Other receivables in the group balance sheet. In addition, contingent consideration receivable relating to disposals amounted to $190 million at 31 December 2024 (2023 $1,694 million and 2022 $1,896 million). The contingent consideration at 31 December 2024 primarily relates to the prior period disposal of certain assets in the North Sea. These amounts of contingent consideration are reported within Other investments on the group balance sheet - see Note 18 for further information.

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

oil production & operations

In 2023 gains principally related to prior period disposals in the US and Canada.

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.

2022 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.

customers & products

In 2024 losses principally related to a loss of $1,132 million arising from the divestment of our Türkiye ground fuels business.

In 2022 gains principally related to a gain of $268 million arising from the divestment of our Swiss retail assets.

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.

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

The principal transactions categorized as a business disposal in 2024 were the divestment of our Türkiye ground fuels business, the new joint venture transaction with ADNOC in Egypt and a transaction relating to the prior period disposal in Alaska.

The principal transactions categorized as a business disposal in 2023 were the sale of the upstream business in Algeria to Eni and the disposal of the bp-Husky Toledo refinery to Cenovus Energy.

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.

4. Disposals and impairment – continued

			$ million
	2024	2023	2022
Non-current assets	**1,775**	1,145	3,681
Current assets	**1,985**	557	2,972
Non-current liabilities	**(548)**	(60)	(1,869)
Current liabilities	**(424)**	(454)	(1,074)
Total carrying amount of net assets disposed	**2,788**	1,188	3,710
Recycling of foreign exchange on disposal	**943**	—	(26)
Costs on disposal	**123**	57	488
	3,854	1,245	4,172
Gains (losses) on sale of businesses	**(888)**	158	6,219
Total consideration	**2,966**	1,403	10,391
Non-cash consideration	**(1,003)**	(51)	(8,999)
Consideration received (receivable)	**615**	(159)	449
Proceeds from the sale of businesses, net of cash disposed[a]	**2,578**	1,193	1,841

a Proceeds are stated net of cash and cash equivalents disposed of $500 million (2023 $33 million and 2022 $318 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 2024 impairment loss of $2,793 million includes amounts in Mauritania & Senegal ($1,495 million), which principally arose as a result of increased forecast future expenditure, and a number of other individually immaterial impairments across the segment principally as a result of portfolio management. The recoverable amounts of these cash generating units (CGUs) were based on value in use or fair value less costs of disposal calculations, as appropriate. The recoverable amount of all CGUs for which impairment charges were recognized in 2024 is $3,423 million.

The 2023 impairment loss of $2,213 million primarily relates to losses incurred in respect of certain assets in Mauritania & Senegal ($1,434 million) and principally arose as a result of increased forecast future expenditure. A further $565 million relates to producing assets in Trinidad and arose as a result of changes to the group's oil and gas price and discount rate assumptions and activity phasing. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2023 in total, based on their value in use, is $4,811 million.

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.

oil production & operations

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

The 2024 impairment loss of $1,155 million primarily arose as a result of changes to reserves and tax assumptions in the North Sea ($1,035 million). The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2024 in total, based on their value in use, is $8,705 million.

The 2023 impairment loss of $1,840 million primarily arose as a result of changes to the group's oil and gas price and discount rate assumptions, activity phasing and disposal decisions in relation to certain assets in North Sea ($852 million) and in bpx energy ($802 million). The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2023 in total, based on their value in use, is $14,072 million.

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.

customers & products

The 2024 impairment loss of $1,661 million primarily arises from the ongoing review of the Gelsenkirchen refinery in Germany ($807 million) and a number of other individually immaterial impairments across the segment, principally as a result of changes to economic assumptions. The recoverable amount 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 2024 in total, based on their value-in-use, is $1,659 million.

The 2023 impairment loss of $1,614 million primarily relates to strategy implementation and changes to economic assumptions in the products business including an impairment of the Gelsenkirchen refinery in Germany ($1,336 million). 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 2023 in total, based on their value in use, is $327 million.

The 2022 impairment loss of $1,874 million primarily relates to changes in economic assumptions in the products business including an 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.

4. Disposals and impairment – continued

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.

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 2024, 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[a] businesses.

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[b]. 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-employment 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 In February 2025 bp announced its intention to move its biogas business to the gas & low carbon energy segment.
b 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 of inventories other than for trading inventories, 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 as inventory holding gains and losses 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.
- an adjustment relating to certain trading inventories that are not price risk managed which relate to a minimum inventory volume that is required to be held to maintain underlying business activities. This adjustment represents the movement in fair value of the inventories due to prices, on a grade-by-grade basis, during the period. This is calculated from each operation’s inventory management system on a monthly basis using the discrete monthly movement in market prices for these inventories.

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 that are price risk-managed.

5. Segmental analysis – continued

						$ million
						2024
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	32,628	25,637	155,401	2,290	(26,771)	189,185
Less: sales and other operating revenues between segments	(1,585)	(23,237)	(317)	(1,632)	26,771	–
Third party sales and other operating revenues	31,043	2,400	155,084	658	–	189,185
Earnings from joint ventures and associates – after interest and tax	504	1,100	393	(4)	–	1,993
Segment results						
Replacement cost profit (loss) before interest and taxation	3,569	10,789	(1,560)	(988)	(25)	11,785
Inventory holding gains (losses)[a]	–	(9)	(479)	–	–	(488)
Profit (loss) before interest and taxation	3,569	10,780	(2,039)	(988)	(25)	11,297
Finance costs						(4,683)
Net finance income relating to pensions and other post-employment benefits						168
Profit before taxation						6,782
Other income statement items						
Depreciation, depletion and amortization						
US	95	4,421	2,142	89	–	6,747
Non-US	4,740	2,376	1,815	944	–	9,875
Charges for provisions, net of write-back of unused provisions, including change in discount rate	38	92	2,602	231	–	2,963
Segment assets						
Investments in joint ventures and associates	4,733	10,730	4,561	8	–	20,032
Additions to non-current assets[b]	11,029	7,296	7,769	1,045	–	27,139

a See explanation of inventory holding gains and losses on page 167.
b Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

5. Segmental analysis – continued

By business	gas & low carbon energy	oil production & operations	customers & products	other businesses & corporate	Consolidation adjustment and eliminations	Total group
						$ million
						2023
Segment revenues						
Sales and other operating revenues	50,297	24,904	160,215	2,657	(27,943)	210,130
Less: sales and other operating revenues between segments	(1,808)	(23,708)	(367)	(2,060)	27,943	—
Third party sales and other operating revenues	48,489	1,196	159,848	597	—	210,130
Earnings from joint ventures and associates – after interest and tax	(677)	1,164	427	(16)	—	898
Segment results						
Replacement cost profit (loss) before interest and taxation	14,080	11,191	4,230	(903)	(14)	28,584
Inventory holding gains (losses)[a]	1	—	(1,237)	—	—	(1,236)
Profit (loss) before interest and taxation	14,081	11,191	2,993	(903)	(14)	27,348
Finance costs						(3,840)
Net finance income relating to pensions and other post-employment benefits						241
Profit before taxation						23,749
Other income statement items						
Depreciation, depletion and amortization						
US	96	3,554	1,883	85	—	5,618
Non-US	5,584	2,138	1,665	923	—	10,310
Charges for provisions, net of write-back of unused provisions, including change in discount rate	139	35	2,007	152	—	2,333
Segment assets						
Investments in joint ventures and associates	4,173	10,721	5,327	28	—	20,249
Additions to non-current assets[b]	4,859	7,384	9,383	1,075	—	22,701

a See explanation of inventory holding gains and losses on page 167.
b Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

5. Segmental analysis – continued

By business	gas & low carbon energy	oil production & operations	customers & products	other businesses & corporate	Consolidation adjustment and eliminations	Total group
						$ million
						2022
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 income relating to pensions and other post-employment 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 167.
b Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

By geographical area	US	Non-US	Total
			$ million
			2024
Revenues			
Third party sales and other operating revenues[a]	**58,804**	**130,381**	**189,185**
Other income statement items			
Production and similar taxes	**149**	**1,650**	**1,799**
Non-current assets			
Non-current assets[b c]	**63,415**	**81,937**	**145,352**

a Non-US region includes UK $24,577 million
b Non-US region includes UK $25,354 million
c Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

By geographical area	US	Non-US	Total
			$ million
			2023
Revenues			
Third party sales and other operating revenues[a]	60,577	149,553	210,130
Other income statement items			
Production and similar taxes	136	1,643	1,779
Non-current assets			
Non-current assets[b c]	64,238	83,816	148,054

a Non-US region includes UK $39,975 million.
b Non-US region includes UK $23,949 million.
c Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

5. Segmental analysis – continued

By geographical area	US	Non-US	$ million 2022 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.

6. Sales and other operating revenues

	2024	2023	$ million 2022
Crude oil	**2,219**	2,413	6,309
Oil products	**121,019**	128,969	149,854
Natural gas, LNG and NGLs	**24,464**	29,541	41,770
Non-oil products and other revenues from contracts with customers	**13,362**	10,298	7,896
Revenue from contracts with customers	**161,064**	171,221	205,829
Other operating revenues[a]	**28,121**	38,909	35,563
Total sales and other operating revenues	**189,185**	210,130	241,392

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

	2024	2023	$ million 2022
Interest and other income			
Interest income from			
Financial assets measured at amortized cost	**1,308**	1,034	371
Financial assets measured at fair value through profit or loss	**181**	215	59
Other income[a]	**1,284**	386	673
	2,773	1,635	1,103
Currency exchange losses charged to the income statement[b]	**541**	74	160
Expenditure on research and development	**301**	298	274
Costs relating to the Gulf of America oil spill (pre-interest and tax)[c]	**51**	57	84
Finance costs			
Interest expense on lease liabilities	**468**	363	245
Interest expense on other liabilities measured at amortized cost[d]	**3,483**	3,115	2,070
Capitalized at 4.94% (2023 4.88% and 2022 3.56%)[e]	**(382)**	(514)	(464)
Finance debt risk management activities[f]	**104**	(35)	43
Unwinding of discount on provisions	**617**	504	369
Unwinding of discount on other payables measured at amortized cost	**393**	407	440
	4,683	3,840	2,703

a 2024 includes a $427 million gain relating to the remeasurement of bp's previously held interests in bp Bunge Bioenergia and Lightsource bp and $498 million relating to the remeasurement of certain US assets excluded from the Lightsource bp acquisition. See Note 3 for further information.
b Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.
c Included within production and manufacturing expenses.
d 2023 includes a loss of $49 million and 2022 a gain of $37 million associated with the buyback of finance debt.
e Tax relief on capitalized interest is approximately $53 million (2023 $130 million and 2022 $108 million).
f Includes temporary valuation differences related to the group's interest rate and foreign currency exchange risk management associated with finance debt.

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
	2024	2023	2022
Exploration and evaluation costs			
Exploration expenditure written off	**767**	746	385
Other exploration costs	**207**	251	200
Exploration expense for the year	**974**	997	585
Impairment losses	**6**	20	2
Intangible assets – exploration and appraisal expenditure[a]	**4,438**	4,328	4,213
Liabilities	**76**	109	88
Net assets	**4,362**	4,219	4,125
Cash used in operating activities	**207**	251	200
Cash used in investing activities	**1,513**	1,039	909

a Amount capitalized at 31 December 2024, 2023 and 2022 relates to assets in various regions. This includes $746 million in the North Africa region (2023 $593 million, 2022 $410 million), $651 million in the Azerbaijan Georgia and Turkiye region (2023 $631 million, 2022 $539 million) and $543 million in the Middle East region (2023 $589 million, 2022 $639 million).

9. Taxation

Tax on profit

			$ million
	2024	2023	2022
Current tax			
Charge for the year[a]	**7,187**	9,048	12,523
Adjustment in respect of prior years	**234**	(373)	145
	7,421	8,675	12,668
Deferred tax			
Origination and reversal of temporary differences in the current year[b]	**(1,851)**	(238)	4,768
Adjustment in respect of prior years[c]	**(17)**	(568)	(674)
	(1,868)	(806)	4,094
Tax charge on profit	**5,553**	7,869	16,762

a 2024 includes a charge of $4 million in respect of Pillar Two income taxes.
b 2024 includes a charge of $96 million in respect of the 3% increase in the UK Energy Profits Levy from 1 November 2024 (see Note 1 for further information). 2022 includes a charge of $1,834 million in respect of the impact of the UK Energy Profits Levy on existing temporary differences unwinding over the period 1 January 2023 to 31 March 2028.
c The adjustment in respect of prior years reflects 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. 2024 also includes a charge of $213 million (2023 $232 million credit) in respect of a revision to the deferred tax impact of the UK Energy Profits Levy.

In 2024, the total tax credit recognized within other comprehensive income was $782 million (2023 $735 million credit and 2022 $266 million charge). In 2024 this primarily comprises a $658 million credit in respect of the reduction in the deferred tax liability on defined benefit pension plan surpluses following the reduction in the rate of the authorized surplus payments tax charge in the UK from 35% to 25%. In 2023 this primarily comprises the deferred tax impact of the remeasurements of the net pension and other post-employment benefit liability or asset. In 2022 this primarily comprises a release of deferred withholding tax on other comprehensive income movements relating to Rosneft. See Note 32 for further information.

The total tax charge recognized directly in equity was $167 million (2023 $56 million charge and 2022 $214 million credit). In 2024 this mainly relates to share-based payments and transactions involving non-controlling interests. In 2023 and 2022 this mainly relates to transactions involving non-controlling interests.

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
	2024	2023	2022 excluding impact of Rosneft	2022 impact of Rosneft[a]	2022
Profit (loss) before taxation	**6,782**	23,749	40,925	(25,520)	15,405
Tax charge (credit) on profit or loss[b]	**5,553**	7,869	17,823	(1,061)	16,762
Effective tax rate	**82%**	33%	44%	4%	109%
					%
Tax rate computed at the weighted average statutory rate[c]	**66**	34	42	20	77
Increase (decrease) resulting from					
Tax reported in equity-accounted entities	**(7)**	(2)	(1)	–	(4)
Adjustments in respect of prior years	**3**	(4)	(1)	–	(3)
Deferred tax not recognized	**5**	2	(1)	–	(2)
Tax incentives for investment	**(2)**	–	–	–	(1)
Disposal impacts[d]	**5**	–	(3)	–	(8)
Foreign exchange	**5**	–	1	–	3
Items not deductible for tax purposes	**5**	2	2	–	5
Impact of bp's decision to exit its shareholding in Rosneft	**–**	–	–	(16)	27
Tax rate change effect of UK Energy Profits Levy[e]	**1**	–	4	–	12
Other[f]	**1**	1	1	–	3
Effective tax rate	**82**	33	44	4	109

a Includes the impact of bp's decision to exit its shareholding in Rosneft and its other businesses with Rosneft in Russia.
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.
d 2022 primarily relates to the contribution of bp's Angolan business to Azule Energy.
e 2024 comprises the deferred tax impact of a 3% increase in the UK Energy Profits Levy (EPL) on existing temporary differences. 2022 includes the deferred tax impact of the introduction of the EPL.
f Includes the impact of adjustments arising in countries where income tax is paid on our behalf by our government partners for which there is no deferred tax effect. 2024 includes the impact of the non-taxable gain relating to the remeasurement of bp's pre-existing 49.97% interest in Lightsource bp and the remeasurement of certain US assets excluded from the Lightsource bp acquisition.

Deferred tax

		$ million
Analysis of movements during the year in the net deferred tax liability	**2024**	2023
At 1 January	**5,349**	6,618
Exchange adjustments	**57**	134
Charge (credit) for the year in the income statement	**(1,868)**	(806)
Charge (credit) for the year in other comprehensive income	**(807)**	(735)
Charge (credit) for the year in equity	**167**	56
Acquisitions and disposals	**127**	82
At 31 December	**3,025**	5,349

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	
	2024	2023	2022	**2024**	2023
Deferred tax liability					
Depreciation	**(1,337)**	(1,552)	1,863	**16,333**	17,392
Pension plan surpluses[a]	**62**	133	42	**1,789**	2,568
Derivative financial instruments	**40**	12	(21)	**58**	12
Other taxable temporary differences[b]	**(352)**	10	(992)	**663**	1,020
	(1,587)	(1,397)	892	**18,843**	20,992
Deferred tax asset					
Depreciation	**(229)**	(166)	(309)	**(2,373)**	(2,141)
Lease liabilities	**(209)**	(176)	(8)	**(1,952)**	(1,785)
Pension plan and other post-employment benefit plan deficits	**28**	(60)	47	**(623)**	(755)
Decommissioning, environmental and other provisions	**425**	563	770	**(5,623)**	(6,042)
Derivative financial instruments	**(9)**	(14)	(6)	**(268)**	(136)
Tax credits	**(43)**	(67)	1,578	**(937)**	(893)
Loss carry forward	**194**	296	1,536	**(2,285)**	(2,467)
Other deductible temporary differences[c]	**(438)**	215	(406)	**(1,757)**	(1,424)
	(281)	591	3,202	**(15,818)**	(15,643)
Net deferred tax charge (credit) and net deferred tax liability	**(1,868)**	(806)	4,094	**3,025**	5,349
Of which – deferred tax liabilities				**8,428**	9,617
– deferred tax assets				**5,403**	4,268

a The 2024 balance sheet reflects a $658 million reduction in the deferred tax liability on defined benefit pension plan surpluses following the reduction in the rate of the authorized surplus payments tax charge in the UK from 35% to 25%.
b The 2022 income statement includes amounts relating to deferred withholding tax on unremitted earnings of Rosneft. The 2024 and 2023 balance sheet amounts do not include any temporary differences that are individually significant.
c The 2024 and 2023 balance sheet amounts include amounts relating to share based payments and other items.

Of the $5,403 million of deferred tax assets recognized on the group balance sheet at 31 December 2024 (2023 $4,268 million), $3,232 million (2023 $2,336 million) relates to entities that have suffered a loss in either the current or preceding period. For 2024, this mainly includes $1,680 million in Germany, $744 million in Mauritania and $609 million in Senegal (2023 mainly included $1,003 million in Germany, $672 million in Mauritania and $500 million in Senegal). For 2024 these amounts are supported by forecasts consistent with bp's future oil and gas price assumptions (see Note 1 for further information) and for Germany, forecast profits associated with the customers & products businesses, that indicate sufficient future taxable profits will be available to utilize such assets within any applicable expiry period.

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

		$ billion
At 31 December	**2024**	2023
Unused US state tax losses[a]	**2.3**	2.1
Unused tax losses – other jurisdictions[b]	**7.3**	5.6
Unused tax credits	**33.3**	31.3
of which – arising in the UK[c]	**29.1**	27.3
– arising in the US[d]	**4.2**	4.0
Deductible temporary differences[e]	**23.4**	20.7
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	**0.7**	0.7

a For 2024 the majority of the unused tax losses have no fixed expiry date.
b 2024 and 2023 mainly relate to the UK, Brazil and Canada. The majority of the unused tax losses have no fixed expiry date.
c The UK unused tax credits arise predominantly in overseas branches of UK entities based in jurisdictions with higher statutory corporate income tax rates than the UK. No deferred tax asset has been recognized on these tax credits as they are unlikely to have value in the future; UK taxes on these overseas branches are largely mitigated by double tax relief in respect of overseas tax. These tax credits have no fixed expiry date.
d 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 2024 these tax credits expire in the period 2025-2034.
e 2024 and 2023 mainly comprise fixed asset temporary differences in overseas branches of UK entities. Substantially all of the temporary differences have no expiry date.

			$ million
Impact of previously unrecognized deferred tax or write-down of deferred tax assets on tax charge	**2024**	2023	2022
Current tax benefit relating to the utilization of previously unrecognized deferred tax assets	**87**	360	492
Deferred tax benefit arising from the reversal of a previous write-down of deferred tax assets	**14**	3	—
Deferred tax benefit relating to the recognition of previously unrecognized deferred tax assets	**280**	332	792
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	**111**	54	—

10. Dividends

The quarterly dividend which is expected to be paid on 28 March 2025 in respect of the fourth quarter 2024 is 8.000 cents per ordinary share ($0.48 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 17 March 2025.

	Pence per share			Cents per share			$ million		
	2024	2023	2022	**2024**	2023	2022	**2024**	2023	2022
Dividends announced and paid in cash									
Preference shares							**1**	1	1
Ordinary shares									
March	**5.6922**	5.5507	4.1595	**7.270**	6.610	5.460	**1,218**	1,183	1,068
June	**5.6825**	5.3089	4.3556	**7.270**	6.610	5.460	**1,204**	1,152	1,061
September	**6.0498**	5.7320	5.1684	**8.000**	7.270	6.006	**1,297**	1,249	1,140
December	**6.2959**	5.7367	4.9402	**8.000**	7.270	6.006	**1,283**	1,224	1,088
	23.7204	22.3283	18.6237	**30.540**	27.760	22.932	**5,003**	4,809	4,358
Dividend announced, paid in March 2025				**8.000**			**1,265**		

The amount of unclaimed dividends recognized as a liability in other payables at 31 December 2024 is $106 million (2023 $91 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 2024 dividend expected to be paid on 28 March 2025.

The financial statements for the year ended 31 December 2024 do not reflect the dividend announced on 11 February 2025 and which is expected to be paid on 28 March 2025; this will be treated as an appropriation of profit in the year ending 31 December 2025.

11. Earnings per share

			Cents per share
Per ordinary share	**2024**	2023	2022
Basic earnings per share	**2.38**	87.78	(13.10)
Diluted earnings per share	**2.32**	85.85	(13.10)

			Dollars per share
Per American Depositary Share (ADS)[a]	**2024**	2023	2022
Basic earnings per share	**0.14**	5.27	(0.79)
Diluted earnings per share	**0.14**	5.15	(0.79)

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
	2024	2023	2022
Profit (loss) attributable to bp shareholders	**381**	15,239	(2,487)
Less: dividend requirements on preference shares	**1**	1	1
Less: (gain) loss on redemption of perpetual hybrid bonds[a]	**(10)**	—	—
Profit (loss) for the year attributable to bp ordinary shareholders	**390**	15,238	(2,488)

			Shares thousand
	2024	2023	2022
Basic weighted average number of ordinary shares[b]	**16,385,535**	17,360,288	18,987,936
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**431,129**	389,790	—
Weighted average number of ordinary shares outstanding used to calculate diluted earnings per share	**16,816,664**	17,750,078	18,987,936

			Shares thousand
	2024	2023	2022
Basic weighted average number of ordinary shares – ADS equivalent	**2,730,922**	2,893,381	3,164,656
Potential dilutive effect of ordinary shares (ADS equivalent) issuable under employee share-based payment plans	**71,855**	64,965	—
Weighted average number of ordinary shares (ADS equivalent) outstanding used to calculate diluted earnings per share	**2,802,777**	2,958,346	3,164,656

a See Note 32 - *non-controlling interests* for further information.
b Excludes treasury shares. See Note 31 for further information.

11. Earnings per share – continued

The number of ordinary shares outstanding at 31 December 2024, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 15,851,028,983 (2023 16,824,651,796). Between 31 December 2024 and 14 February 2025, the latest practicable date before the completion of these financial statements, there was a net decrease of 118,209,740 of ordinary shares primarily as a result of 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 88-110.

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	2024		2023	
	Number of options[a b] thousand	Weighted average exercise price $	Number of options[a b] thousand	Weighted average exercise price $
Outstanding	**533,895**	**4.15**	545,044	4.04
Exercisable	**2,931**	**3.38**	905	3.31
Dilutive effect	**140,971**	**n/a**	166,581	n/a

a Numbers of options shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).
b At 31 December 2024 the quoted market price of one bp ordinary share was £3.93 (2023 £4.66).

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	2024	2023
Vesting	Number of shares[a] thousand	Number of shares[a] thousand
Within one year	**271,216**	226,190
1 to 2 years	**134,342**	257,511
2 to 3 years	**102,525**	114,500
3 to 4 years	**956**	1,176
Over 4 years	**118**	308
	509,157	599,685
Dilutive effect	**269,796**	284,908

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

There has been a net increase of 10,925,262 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2024 and 14 February 2025.

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 2024	**3,924**	**992**	**185,346**	**47,384**	**2,290**	**2,958**	**12,224**	**255,118**
Exchange adjustments	**(213)**	**(35)**	**—**	**(864)**	**(43)**	**(23)**	**(637)**	**(1,815)**
Additions	**352**	**222**	**7,899**	**3,039**	**138**	**144**	**1,042**	**12,836**
Acquisitions	**60**	**148**	**—**	**1,235**	**57**	**80**	**70**	**1,650**
Transfers from intangible assets	**—**	**—**	**391**	**—**	**—**	**—**	**—**	**391**
Reclassified as assets held for sale	**(25)**	**(41)**	**(3,210)**	**(747)**	**(1)**	**—**	**—**	**(4,024)**
Deletions and disposals	**(38)**	**(119)**	**(6,122)**	**(1,316)**	**(126)**	**(472)**	**(282)**	**(8,475)**
At 31 December 2024	**4,060**	**1,167**	**184,304**	**48,731**	**2,315**	**2,687**	**12,417**	**255,681**
Depreciation - owned PP&E								
At 1 January 2024	**838**	**553**	**123,442**	**25,671**	**1,684**	**2,292**	**6,363**	**160,843**
Exchange adjustments	**(52)**	**(9)**	**—**	**(536)**	**(24)**	**(9)**	**(388)**	**(1,018)**
Charge for the year	**58**	**43**	**10,626**	**1,553**	**157**	**91**	**731**	**13,259**
Impairment losses	**70**	**—**	**2,418**	**1,260**	**1**	**9**	**82**	**3,840**
Impairment reversals	**—**	**—**	**(420)**	**(4)**	**—**	**(3)**	**—**	**(427)**
Reclassified as assets held for sale	**(6)**	**(4)**	**(2,168)**	**(367)**	**(1)**	**—**	**—**	**(2,546)**
Deletions and disposals	**(32)**	**(63)**	**(5,807)**	**(648)**	**(101)**	**(447)**	**(227)**	**(7,325)**
At 31 December 2024	**876**	**520**	**128,091**	**26,929**	**1,716**	**1,933**	**6,561**	**166,626**
Owned PP&E - net book amount at 31 December 2024	**3,184**	**647**	**56,213**	**21,802**	**599**	**754**	**5,856**	**89,055**
Right-of-use assets - net book amount at 31 December 2024[b]	**—**	**1,613**	**41**	**1,431**	**10**	**2,589**	**5,499**	**11,183**
Total PP&E - net book amount at 31 December 2024	**3,184**	**2,260**	**56,254**	**23,233**	**609**	**3,343**	**11,355**	**100,238**
Cost - owned PP&E								
At 1 January 2023	3,513	950	179,028	44,662	2,202	3,076	10,089	243,520
Exchange adjustments	112	2	—	294	31	2	342	783
Additions	134	48	8,252	2,921	221	80	1,126	12,782
Acquisitions	206	—	—	27	12	48	1,060	1,353
Transfers from intangible assets	—	—	171	—	—	—	—	171
Reclassified as assets held for sale	(7)	—	—	(3)	(3)	(1)	(74)	(88)
Deletions and disposals	(34)	(8)	(2,105)	(517)	(173)	(247)	(319)	(3,403)
At 31 December 2023	3,924	992	185,346	47,384	2,290	2,958	12,224	255,118
Depreciation - owned PP&E								
At 1 January 2023	700	501	111,434	22,903	1,671	2,431	5,819	145,459
Exchange adjustments	14	3	—	200	18	2	206	443
Charge for the year	45	30	10,468	1,519	163	85	629	12,939
Impairment losses	108	22	3,628	1,467	—	10	58	5,293
Impairment reversals	—	—	(18)	—	—	(9)	—	(27)
Reclassified as assets held for sale	(1)	—	—	(2)	(1)	(1)	(74)	(79)
Deletions and disposals	(28)	(3)	(2,070)	(416)	(167)	(226)	(275)	(3,185)
At 31 December 2023	838	553	123,442	25,671	1,684	2,292	6,363	160,843
Owned PP&E - net book amount at 31 December 2023	3,086	439	61,904	21,713	606	666	5,861	94,275
Right-of-use assets - net book amount at 31 December 2023[b]	—	1,243	53	916	4	2,463	5,765	10,444
Total PP&E - net book amount at 31 December 2023	3,086	1,682	61,957	22,629	610	3,129	11,626	104,719

	Land and land improvements	Buildings	Oil and gas properties	Plant, machinery and equipment	Fittings, fixtures and office equipment	Transportation	Oil depots, storage tanks and service stations	Total
Assets under construction included above								
At 31 December 2024								**10,722**
At 31 December 2023								13,390
Depreciation charge for the year on right-of-use assets								
2024		**215**	**30**	**640**	**3**	**1,109**	**882**	**2,878**
2023		196	16	558	5	1,055	783	2,613

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 $867 million (2023 $661 million) of drilling rig right-of-use assets and $2,455 million (2023 $2,337 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 2024 amounted to $13,642 million (2023 $10,354 million, 2022 $9,381 million). bp has contracted capital commitments amounting to $3,392 million (2023 $1,580 million, 2022 $1,764 million) in relation to joint ventures and $59 million (2023 $105 million, 2022 $18 million) in relation to associates.

14. Goodwill and impairment review of goodwill

		$ million
	2024	2023
Cost		
At 1 January	**13,176**	12,577
Exchange adjustments	**(179)**	184
Acquisitions and other additions	**2,734**	415
Reclassified as assets held for sale	**(79)**	—
Deletions and disposals	**(122)**	—
At 31 December	**15,530**	13,176
Impairment losses		
At 1 January	**704**	617
Exchange adjustments	**(2)**	2
Impairment losses for the year	**—**	85
Deletions and disposals	**(60)**	—
At 31 December	**642**	704
Net book amount at 31 December	**14,888**	12,472
Net book amount at 1 January	**12,472**	11,960

Impairment review of goodwill

		$ million
Goodwill at 31 December	**2024**	2023
gas & low carbon energy	**4,460**	2,095
oil production & operations	**4,925**	4,925
customers & products	**5,503**	5,431
other businesses & corporate	**—**	21
	14,888	12,472

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 ('gas businesses') within the segment and to Lightsource bp (LSbp). For customers and products, goodwill has been allocated to Castrol, US Fuels, European Fuels, Archaea 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	
			2024			2023	**2024**	2023
	Gas	**LSbp**	**Total**	Gas	LSbp	Total		
Goodwill	**2,228**	**2,232**	**4,460**	2,095	—	2,095	**4,925**	4,925
Excess of recoverable amount over carrying amount	**2,026**	**—**	**2,026**	5,886	—	5,886	**12,432**	18,854

The table above shows the carrying amount of goodwill for the segments at the period end and the excess of the recoverable amount over the carrying amount (headroom) at the date of the most recent test. The recoverable amount for the gas businesses and the oil production & operations segment is based on a pre-tax value-in-use calculation. The decrease in headroom for both of these goodwill impairment tests is due to changes in a number of assumptions including prices and production as well as, for the oil productions & operations segment, certain tax assumptions and, for the gas businesses, divestments. The recoverable amount for the LSbp goodwill is based on fair value less costs of disposal.

No material impairment of the goodwill balances in either gas & low carbon energy or oil production & operations was recognized during 2024 or 2023.

14. Goodwill and impairment review of goodwill – continued

Gas businesses and oil production & operations

The value in use for relevant CGUs in both the gas businesses 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 the gas businesses 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 businesses over the next 15 years is 154 mmboe per year (2023 185 mmboe per year) and in the oil production and operations segment is 400 mmboe per year (2023 402 mmboe per year). Production assumptions used for the goodwill impairment tests in both the gas businesses and oil production & operations reflect management's best estimate of future production of the existing portfolio at the time of the calculation.

The weighted average pre-tax discount rate used in the review for the oil production & operations segment is 17%, and 11% for the gas businesses (2023 17% for the oil production & operations segment and 11% for the gas businesses).

The most recent reviews for impairment for the oil production & operations and the gas businesses 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 at any given price or production profile may, therefore, produce a different result.

It is estimated that a 11% (2023 22%) 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 the gas businesses a 6% (2023 15%) reduction would have the same result.

It is estimated that no reasonably possible change in the discount rate of the oil production and operations segment would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets. For the gas businesses a 2% increase would have this result (2023 no reasonably possible change).

Lightsource bp

The Lightsource bp goodwill largely relates to the value attributed to the business's project development capability, including the workforce in place. Management considers the fair value of Lightsource bp at 31 December 2024 to be substantially the same as at the date of acquisition in the fourth quarter of 2024.

customers & products

												$ million
						2024						2023
	Castrol	**US Fuels**	**European Fuels**	**Archaea**	**Other**	**Total**	Castrol	US Fuels	European Fuels	Archaea	Other	Total
Goodwill	**2,615**	**828**	**801**	**706**	**553**	**5,503**	2,672	792	839	707	421	5,431

Cash flows for each group of CGUs are derived from the business segment plans, which cover a period of up to five years, except for Archaea where a business plan to 2035 is in place following the acquisition in 2022. To determine the value in use for each of the groups of cash-generating units, cash flows for a period of 10 years (11 years for Archaea), are discounted and aggregated with a terminal value. Pre-tax discount rates ranging from 10-12% are applied. It is estimated that no reasonably possible change in the key assumptions used in the US Fuels, European Fuels and Archaea goodwill impairment assessments would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets.

No material impairment of the goodwill balances in customers & products was recognized during 2024 or 2023.

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 9% (2023 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% (2023 3.4%) growth rate.

15. Intangible assets

								$ million
				2024				2023
	Exploration and appraisal expenditure[a]	**Biogas rights agreements**	**Other intangibles**	**Total**	Exploration and appraisal expenditure[a]	Biogas rights agreements	Other intangibles	Total
Cost								
At 1 January	**13,075**	**2,989**	**7,117**	**23,181**	12,571	3,398	6,817	22,786
Exchange adjustments	**—**	**—**	**(171)**	**(171)**	—	—	144	144
Acquisitions[b]	**—**	**—**	**351**	**351**	—	—	130	130
Remeasurements of acquisition accounting[c]	**—**	**—**	**—**	**—**	—	(394)	—	(394)
Additions	**1,539**	**193**	**904**	**2,636**	1,058	23	799	1,880
Transfers to property, plant and equipment	**(391)**	**—**	**—**	**(391)**	(171)	—	—	(171)
Reclassified as assets held for sale	**(1)**	**—**	**(385)**	**(386)**	—	—	(6)	(6)
Deletions and disposals	**(1,169)**	**(192)**	**(266)**	**(1,627)**	(383)	(38)	(767)	(1,188)
At 31 December	**13,053**	**2,990**	**7,550**	**23,593**	13,075	2,989	7,117	23,181
Amortization								
At 1 January	**8,747**	**105**	**4,338**	**13,190**	8,358	—	4,228	12,586
Exchange adjustments	**—**	**—**	**(97)**	**(97)**	—	—	79	79
Exploration expenditure written off	**767**	**—**	**—**	**767**	746	—	—	746
Charge for the year	**—**	**114**	**717**	**831**	—	106	642	748
Impairment losses	**6**	**344**	**108**	**458**	20	—	77	97
Impairment reversals	**(2)**	**—**	**—**	**(2)**	—	—	—	—
Reclassified as assets held for sale	**—**	**—**	**(53)**	**(53)**	—	—	(3)	(3)
Deletions and disposals	**(903)**	**(6)**	**(238)**	**(1,147)**	(377)	(1)	(685)	(1,063)
At 31 December	**8,615**	**557**	**4,775**	**13,947**	8,747	105	4,338	13,190
Net book amount at 31 December	**4,438**	**2,433**	**2,775**	**9,646**	4,328	2,884	2,779	9,991
Net book amount at 1 January	**4,328**	**2,884**	**2,779**	**9,991**	4,213	3,398	2,589	10,200

a For further information see Intangible assets within Note 1 and Note 8.
b 2024 primarily relates to the acquisition of GETEC ENERGIE GmbH.
c 2023 primarily relates to the acquisition of Archaea Energy Inc.

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
	2024	2023	2022	**2024**	2023
Azule Energy	**504**	700	540	**5,109**	5,066
Pan American Energy Group	**—**	—	538	**—**	—
Other joint ventures[a]	**405**	(633)	50	**7,182**	7,369
	909	67	1,128	**12,291**	12,435

a 2024 and 2023 includes Pan American Energy Group as no longer considered material to the group post 2022 impairment.

The joint venture that is material to the group at 31 December 2024 is Azule Energy, which was formed during 2022 and in which bp owns a 50% stake.

bp classifies its investment in Azule Energy Holdings Limited as a joint venture because, per the terms of the shareholders' agreements, bp has joint control over Azule Energy. Azule Energy Holdings Limited is based in Angola and its functional currency is USD.

Following the 2022 impairment of bp's investment in PAEG, this is no longer considered material to the group for 2023 and 2024 and is now included with Other joint ventures.

The following table provides summarized financial information relating to Azule Energy for 2024, 2023 and 2022 and Pan American Energy Group for 2022. 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.

16. Investments in joint ventures – continued

The operational and financial information is based on preliminary operational and financial results of Azule Energy Holdings Limited for 2024, 2023 and 2022 and Pan American Energy Group S.L. for 2022. Actual results may differ from these amounts - immaterial adjustments to the 2023 and 2022 numbers for Azule Energy Holdings Limited have been included in the 2024 and 2023 numbers respectively.

				$ million
				Gross amount
	2024	2023		2022
	Azule Energy	Azule Energy	Azule Energy	PAEG
Sales and other operating revenues	**5,410**	5,164	2,274	6,408
Profit (loss) before interest and taxation	**1,896**	2,146	1,460	1,560
Finance costs	**512**	400	218	376
Profit (loss) before taxation[a]	**1,384**	1,746	1,242	1,184
Taxation	**376**	346	162	108
Profit (loss) for the year	**1,008**	1,400	1,080	1,076
Other comprehensive income	**—**	—	—	—
Total comprehensive income	**1,008**	1,400	1,080	1,076
Non-current assets	**20,584**	18,788		
Current assets[b]	**3,384**	3,928		
Total assets	**23,968**	22,716		
Current liabilities[c]	**3,576**	2,510		
Non-current liabilities[d]	**10,174**	10,074		
Total liabilities	**13,750**	12,584		
Net assets	**10,218**	10,132		
Less: non-controlling interests	**—**	—		
	10,218	10,132		

a Azule Energy includes depreciation and amortisation of $2,844 million (2023 $2,768 million and 2022 $1,145 million), interest income of $nil (2023 $nil and 2022 $11 million) and interest expense of $513 million (2023 $407 million and 2022 $218 million). For 2022 PAEG includes depreciation and amortisation of $1,039 million, interest income of $29 million and interest expense of $375 million.
b Azule Energy includes cash and cash equivalents of $570 million (2023 $603 million).
c Azule Energy includes current financial liabilities of $3,417 million (2023 $2,409 million).
d Azule Energy includes non-current financial liabilities of $3,426 million (2023 $4,735 million).

The group received dividends of $463 million from Azule Energy Holdings Limited in 2024 (2023 $708 million and 2022 $500 million).

The group received dividends, net of withholding tax, of $35 million from Pan American Energy Group S.L. in 2022.

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

										$ million
										bp share
			2024			2023				2022
	Azule Energy	Other	Total	Azule Energy	Other	Total	Azule Energy	PAEG	Other	Total
Sales and other operating revenues	**2,705**	**12,164**	**14,869**	2,582	13,705	16,287	1,137	3,204	9,770	14,111
Profit (loss) before interest and taxation	**948**	**(74)**	**874**	1,073	8	1,081	730	780	255	1,765
Finance costs	**256**	**249**	**505**	200	421	621	109	188	137	434
Profit (loss) before taxation	**692**	**(323)**	**369**	873	(413)	460	621	592	118	1,331
Taxation	**188**	**(729)**	**(541)**	173	219	392	81	54	67	202
Non-controlling interest	**—**	**1**	**1**	—	1	1	—	—	1	1
Profit (loss) for the year	**504**	**405**	**909**	700	(633)	67	540	538	50	1,128
Other comprehensive income	**—**	**(3)**	**(3)**	—	45	45	—	—	50	50
Total comprehensive income	**504**	**402**	**906**	700	(588)	112	540	538	100	1,178
Non-current assets	**10,292**	**13,871**	**24,163**	9,394	16,505	25,899				
Current assets	**1,692**	**4,363**	**6,055**	1,964	4,387	6,351				
Total assets	**11,984**	**18,234**	**30,218**	11,358	20,892	32,250				
Current liabilities	**1,788**	**2,914**	**4,702**	1,255	2,992	4,247				
Non-current liabilities	**5,087**	**5,057**	**10,144**	5,037	7,505	12,542				
Total liabilities	**6,875**	**7,971**	**14,846**	6,292	10,497	16,789				
Net assets	**5,109**	**10,263**	**15,372**	5,066	10,395	15,461				
Less: non-controlling interests	**—**	**(11)**	**(11)**	—	(15)	(15)				
	5,109	**10,252**	**15,361**	5,066	10,380	15,446				
Group investment in joint ventures										
Group share of net assets (as above)	**5,109**	**10,252**	**15,361**	5,066	10,380	15,446				
Cumulative impairment charge	**—**	**(3,066)**	**(3,066)**	—	(3,007)	(3,007)				
Loans made by group companies to joint ventures	**—**	**(4)**	**(4)**	—	(4)	(4)				
	5,109	**7,182**	**12,291**	5,066	7,369	12,435				

16. Investments in joint ventures – continued

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

						$ million
Sales to joint ventures		**2024**		2023		2022
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	**3,653**	**507**	3,585	501	4,212	316

Purchases from joint ventures		**2024**		2023		2022
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	**2,952**	**468**	3,328	427	1,893	574

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 2024 relate to heating oil, gasoline, diesel and lubricant product transactions with Mobene and Ocwen Energy. The majority of purchases from joint ventures in 2024 relate to crude oil and oil products transactions with Azule Energy.

bp's share of net impairment charges recognized by joint ventures in 2024 was $477 million (2023 $1,285 million and 2022 $256 million) of which $nil charge (2023 $1,152 million and 2022 $276 million) was in the gas and low carbon energy segment and $477 million charge (2023 $133 million charge and 2022 reversals of $20 million) was in the oil production & operations segment. The 2023 charges in the gas and low carbon energy segment principally relate to the group's US offshore wind investments.

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 2024. 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. Since the first quarter 2022, bp accounts for its interest in Rosneft and its other businesses with Rosneft within Russia, as financial assets measured at fair value within 'Other investments'. For further information see Note 1 *Significant judgements and estimate: investment in Rosneft*.

					$ million
			Income statement		Balance sheet
			Earnings from associates - after interest and tax		Investments in associates
	2024	2023	2022	**2024**	2023
Rosneft	**—**	—	528	**—**	—
Other associates	**1,084**	831	874	**7,741**	7,814
	1,084	831	1,402	**7,741**	7,814

The group recognized dividends, net of withholding tax, of $nil from Rosneft in 2024 (2023 $nil and 2022 $nil).

17. Investments in associates – continued

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

			$ million
			bp share
	2024	2023	2022
Sales and other operating revenues	12,859	11,396	14,841
Profit before interest and taxation	2,389	2,279	3,053
Finance costs	41	41	73
Profit (loss) before taxation	2,348	2,238	2,980
Taxation	1,264	1,407	1,498
Non-controlling interests	—	—	80
Profit (loss) for the year	1,084	831	1,402
Other comprehensive income	(9)	(237)	352
Total comprehensive income	1,075	594	1,754
Non-current assets	11,395	11,483	
Current assets	4,230	3,776	
Total assets	15,625	15,259	
Current liabilities	3,009	3,003	
Non-current liabilities	4,886	4,473	
Total liabilities	7,895	7,476	
Net assets	7,730	7,783	
Less: non-controlling interests	—	—	
	7,730	7,783	
Group investment in associates			
Group share of net assets (as above)	7,730	7,783	
Loans made by group companies to associates	11	31	
	7,741	7,814	

Transactions between the group and its associates are summarized below.

						$ million
Sales to associates		2024		2023		2022
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	844	148	1,009	368	1,042	417

						$ million
Purchases from associates		2024		2023		2022
Product	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
Crude oil and oil products, natural gas, transportation tariff	7,034	2,223	5,473	2,607	6,199	2,086

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 2024, 2023 and 2022 relate to crude oil and oil products transactions with Aker BP. Sales to associates are related to various entities.

bp has commitments amounting to $7,921 million million (2023 $8,615 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 2024 was $14 million (2023 $nil).

18. Other investments

				$ million
		2024		2023
	Current	Non-current	Current	Non-current
Equity investments[a]	—	1,095	—	1,177
Contingent consideration	55	136	754	939
Other	110	61	89	73
	165	1,292	843	2,189

a The majority of equity investments are unlisted.

Unlisted equity investments are measured using observable recent market prices where available. The majority of investments are measured using models with inputs that may include recent share price data, discounted future cash flows and other available active market pricing data using the maximum available market information and bp's understanding of the associated company's performance and prospects. Contingent consideration relates to amounts arising on disposals which are financial assets classified as measured at fair value through profit or loss. The contingent consideration in 2023 principally relates to the disposal of our Alaskan business. On 4 October 2024, bp completed the sale of this contingent consideration.

19. Inventories

		$ million
	2024	2023
Crude oil	3,007	3,227
Natural gas	548	410
Emissions allowances	549	464
Refined petroleum and petrochemical products	6,627	7,413
	10,731	11,514
Trading inventories	8,977	9,850
Supplies	1,946	1,455
Biological assets	178	—
Solar projects	1,400	—
	23,232	22,819
Cost of inventories expensed in the income statement	113,941	119,307

The inventory valuation at 31 December 2024 is stated net of a provision of $388 million (2023 $497 million) to write down inventories to their net realizable value, of which $199 million (2023 $310 million) relates to hydrocarbon inventories. The net credit to the income statement in the year in respect of inventory net realizable value provisions was $77 million (2023 $87 million charge), of which $104 million credit (2023 $112 million charge) related to hydrocarbon inventories.

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

20. Trade and other receivables

				$ million
		2024		2023
	Current	Non-current	Current	Non-current
Financial assets				
Trade receivables	21,659	502	25,175	652
Amounts receivable from joint ventures and associates	655	—	843	26
Other receivables	3,524	808	3,936	722
	25,838	1,310	29,954	1,400
Non-financial assets				
Sales taxes and production taxes	1,165	356	1,028	355
Other receivables	124	149	141	12
	1,289	505	1,169	367
	27,127	1,815	31,123	1,767

In both 2024 and 2023 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

	2024		2023		2022	
$ million	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments
At 1 January	**1,424**	**3,183**	636	3,050	584	169
Charged to costs and expenses	**(90)**	**140**	866	176	143	17,471
Charged to other accounts[a]	**(7)**	**—**	1	(1)	(8)	(27)
Deductions	**(332)**	**(25)**	(79)	(42)	(83)	(41)
Reclassifications	**—**	**—**	—	—	—	(14,522)
At 31 December	**995**	**3,298**	1,424	3,183	636	3,050

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 $858 million (2023 $1,301 million, 2022 $513 million) relating to receivables that were credit-impaired at the end of the year and $137 million (2023 $123 million, 2022 $123 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 2022 principally relates to bp's investments in Rosneft and Pan American Energy Group S.L.. Amounts related to bp's investments in Rosneft and other businesses with Rosneft within Russia were reclassified in 2022 following bp's loss of significant influence.

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

	2024		2023	
$ million	Current	Non-current	Current	Non-current
Financial liabilities				
Trade payables	**38,636**	**—**	42,406	—
Amounts payable to joint ventures and associates	**2,690**	**1**	3,034	—
Payables for capital expenditure and acquisitions	**3,670**	**309**	3,063	305
Payables related to the Gulf of America oil spill	**1,126**	**6,830**	1,130	7,602
Other payables	**7,358**	**678**	7,313	663
	53,480	**7,818**	56,946	8,570
Non-financial liabilities				
Sales taxes, customs duties, production taxes and social security	**2,121**	**54**	2,264	134
Other payables	**2,810**	**1,537**	1,945	1,372
	4,931	**1,591**	4,209	1,506
	58,411	**9,409**	61,155	10,076

Materially all of bp's trade payables have payment terms of less than 60 days and give rise to operating cash flows.

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

Payables related to the Gulf of America 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 America oil spill for these elements of the agreements are $3,450 million payable over 8 years, $1,926 million payable over 9 years and $2,549 million payable over 8 years respectively at 31 December 2024. Reported within net cash provided by operating activities in the group cash flow statement is a net cash outflow of $1,192 million (2023 outflow of $1,280 million, 2022 outflow of $1,370 million) related to the Gulf of America 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 America oil spill at 31 December 2024 also include amounts payable for settled economic loss and property damage claims which are payable over a period of up to three years.

23. Provisions

	Decommissioning	Environmental	Litigation and claims	Emissions	Other[c]	Total
						$ million
At 1 January 2024	**12,372**	**1,614**	**727**	**3,025**	**1,401**	**19,139**
Exchange adjustments	**(53)**	**(9)**	**(9)**	**(58)**	**(67)**	**(196)**
Acquisitions	**—**	**—**	**29**	**—**	**11**	**40**
New and increase in existing provisions[a]	**942**	**254**	**125**	**1,931**	**1,445**	**4,697**
Write-back of unused provisions[a]	**—**	**(35)**	**(18)**	**(339)**	**(333)**	**(725)**
Unwinding of discount[b]	**499**	**61**	**20**	**—**	**37**	**617**
Change in discount rate	**(886)**	**(38)**	**(22)**	**—**	**(7)**	**(953)**
Utilization	**(52)**	**(287)**	**(151)**	**(2,229)**	**(479)**	**(3,198)**
Reclassified to other payables	**(591)**	**(21)**	**—**	**—**	**(6)**	**(618)**
Reclassified as liabilities directly associated with assets held for sale	**(40)**	**—**	**—**	**—**	**(5)**	**(45)**
Deletions	**(433)**	**(21)**	**—**	**—**	**(16)**	**(470)**
At 31 December 2024	**11,758**	**1,518**	**701**	**2,330**	**1,981**	**18,288**
Of which – current	**641**	**351**	**109**	**1,877**	**622**	**3,600**
– non-current	**11,117**	**1,167**	**592**	**453**	**1,359**	**14,688**

a Recognized in the Group income statement, other than changes in decommissioning provisions related to owned assets.
b Recognized in the Group income statement
c Other includes provisions for onerous contracts and restructuring costs.

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 America oil spill

The group has recognized certain assets, payables and provisions and incurs certain residual costs relating to the Gulf of America 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 America oil spill. The amounts payable may differ from the amount provided and the timing of payments is uncertain.

24. Pensions and other post-employment 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-employment benefits in Note 1.

The defined benefit pension obligation in the UK consists primarily of a closed 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.

Employees in the UK are eligible for membership of defined contribution plans established with third-party providers.

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. At the end of 2024 the committee was composed of five 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-employment 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 2024 the aggregate level of contributions was $69 million (2023 $42 million and 2022 $74 million). The aggregate level of contributions in 2025 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 defined benefit 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 2026 formal actuarial valuation. No contractually committed funding was due at 31 December 2024.

The surplus relating to the primary UK defined benefit 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 2024 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 2024.

The obligation and cost of providing pensions and other post-employment benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2024. The UK defined benefit 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 primary UK defined benefit pension plan was as at 31 December 2023. A valuation of the US plan and largest Eurozone plans are carried out annually.

24. Pensions and other post-employment 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.

									%
			UK			US			Eurozone
Financial assumptions used to determine benefit obligation	**2024**	2023	2022	**2024**	2023	2022	**2024**	2023	2022
Discount rate for plan liabilities	**5.5**	4.8	5.0	**5.6**	5.0	5.2	**3.5**	3.6	4.2
Rate of increase for pensions in payment	**2.9**	2.8	2.9	**—**	—	—	**1.8**	2.1	1.8
Rate of increase in deferred pensions	**2.9**	2.8	2.9	**—**	—	—	**0.6**	0.7	0.6
Inflation for plan liabilities	**3.1**	3.0	3.1	**2.0**	2.0	2.0	**2.0**	2.4	2.1

									%
			UK			US			Eurozone
Financial assumptions used to determine benefit expense	**2024**	2023	2022	**2024**	2023	2022	**2024**	2023	2022
Discount rate for plan service cost[a]	**N/A**	N/A	N/A	**5.0**	5.2	2.8	**3.7**	4.3	1.7
Discount rate for plan other finance expense	**4.8**	5.0	1.8	**5.0**	5.2	2.7	**3.6**	4.2	1.3
Inflation for plan service cost[a]	**N/A**	N/A	N/A	**2.0**	2.0	2.1	**2.4**	2.1	1.6

a UK discount rate and inflation rate assumptions are not relevant in determining the benefit expense for the closed UK plan. Rates for the remaining small worldwide plan administered/reported through the UK are 5.0% (2023 5.0% and 2022 2.5%) and 1.9% (2023 1.9% and 2022 2.2%) respectively.

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:

									Years
Mortality assumptions			UK			US			Eurozone
	2024	2023	2022	**2024**	2023	2022	**2024**	2023	2022
Life expectancy at age 60 for a male currently aged 60	**27.0**	27.4	26.9	**25.1**	25.0	25.0	**26.2**	26.1	26.0
Life expectancy at age 60 for a male currently aged 40	**28.9**	29.2	28.5	**26.8**	26.7	26.6	**28.6**	28.6	28.5
Life expectancy at age 60 for a female currently aged 60	**29.0**	29.2	28.8	**28.1**	28.1	28.0	**29.5**	29.3	29.3
Life expectancy at age 60 for a female currently aged 40	**30.5**	30.6	30.6	**29.6**	29.6	29.5	**31.7**	31.6	31.4

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

A 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 defined benefit 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 defined benefit plan there is an agreement with the trustee to at least maintain the proportion of assets with liability matching characteristics and review over time. There is a similar agreement in place for the primary US plan. During 2024, the asset allocation policies of the primary UK and US plans remained unchanged.

The current asset allocation policy for the major plans at 31 December 2024 was as follows:

	UK	**US**
Asset category	**%**	**%**
Total equity (including private equity)	**8**	**19**
Bonds/cash (including LDI)	**85**	**81**
Property/real estate	**7**	**—**

24. Pensions and other post-employment benefits – continued

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2024 were $4,970 million (2023 $6,215 million) of government-issued nominal bonds and $11,105 million (2023 $13,177 million) of index-linked bonds.

Some of the group's pension plans in the Eurozone and other countries use derivative financial instruments as part of their asset mix to manage the level of risk. The fair value of these instruments 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 190.

					$ million
	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2024					
Listed equities – developed markets	**963**	**113**	**341**	**230**	**1,647**
– emerging markets	**32**	**13**	**55**	**75**	**175**
Private equity[c]	**1,916**	**950**	**—**	**2**	**2,868**
Government issued nominal bonds[d]	**5,027**	**1,317**	**690**	**223**	**7,257**
Government issued index-linked bonds[d]	**11,105**	**—**	**78**	**7**	**11,190**
Corporate bonds[d]	**6,088**	**2,763**	**605**	**261**	**9,717**
Property[e]	**2,344**	**—**	**84**	**19**	**2,447**
Cash	**416**	**67**	**100**	**78**	**661**
Other	**1,039**	**36**	**54**	**14**	**1,143**
Debt (repurchase agreements) used to fund liability driven investments	**(5,664)**	**—**	**—**	**—**	**(5,664)**
	23,266	**5,259**	**2,007**	**909**	**31,441**
At 31 December 2023					
Listed equities – developed markets	862	97	333	232	1,524
– emerging markets	28	12	51	66	157
Private equity[c]	2,022	1,014	—	2	3,038
Government issued nominal bonds[d]	6,285	1,457	746	285	8,773
Government issued index-linked bonds[d]	13,177	—	88	—	13,265
Corporate bonds[d]	6,144	2,802	605	166	9,717
Property[e]	2,437	—	92	17	2,546
Cash	453	59	82	85	679
Other[f]	1,123	33	55	391	1,602
Debt (repurchase agreements) used to fund liability driven investments	(6,485)	—	—	—	(6,485)
	26,046	5,474	2,052	1,244	34,816
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

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 included insurance policies arising from annuity buy-in in Canada amounting to $374 million in 2023 (2022 $341 million). Completion of a buy-out in 2024 reduced these amounts to nil.

24. Pensions and other post-employment benefits – continued

					$ million
					2024
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	48	160	62	23	293
Past service cost[b]	–	–	(1)	–	(1)
Settlement[b]	(1)	–	–	–	(1)
Operating charge (credit) relating to defined benefit plans	47	160	61	23	291
Payments to defined contribution plans	161	192	8	35	396
Total operating charge (credit)	208	352	69	58	687
Interest income on plan assets[a]	(1,218)	(267)	(70)	(49)	(1,604)
Interest on plan liabilities	909	283	184	60	1,436
Other finance (income) expense	(309)	16	114	11	(168)
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	(2,388)	(239)	65	83	(2,479)
Change in financial assumptions underlying the present value of the plan liabilities	1,496	403	103	(48)	1,954
Change in demographic assumptions underlying the present value of the plan liabilities	194	(8)	1	2	189
Experience gains and losses arising on the plan liabilities	15	(34)	2	(7)	(24)
Remeasurements recognized in other comprehensive income	(683)	122	171	30	(360)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	19,579	5,837	5,537	1,371	32,324
Exchange adjustments	(352)	–	(355)	(66)	(773)
Operating charge relating to defined benefit plans	47	160	61	23	291
Interest cost	909	283	184	60	1,436
Contributions by plan participants	7	–	2	7	16
Benefit payments (funded plans)[c]	(1,153)	(243)	(89)	(427)	(1,912)
Benefit payments (unfunded plans)[c]	(8)	(152)	(232)	(12)	(404)
Disposals	–	–	–	(2)	(2)
Remeasurements	(1,705)	(361)	(106)	53	(2,119)
Benefit obligation at 31 December[a d]	17,324	5,524	5,002	1,007	28,857
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	26,046	5,474	2,052	1,244	34,816
Exchange adjustments	(473)	–	(139)	(61)	(673)
Interest income on plan assets[a e]	1,218	267	70	49	1,604
Contributions by plan participants	7	–	2	7	16
Contributions by employers (funded plans)	9	–	46	14	69
Benefit payments (funded plans)[c]	(1,153)	(243)	(89)	(427)	(1,912)
Remeasurements[e]	(2,388)	(239)	65	83	(2,479)
Fair value of plan assets at 31 December[f]	23,266	5,259	2,007	909	31,441
Surplus (deficit) at 31 December	5,942	(265)	(2,995)	(98)	2,584
Represented by					
Asset recognized	6,083	1,009	273	92	7,457
Liability recognized	(141)	(1,274)	(3,268)	(190)	(4,873)
	5,942	(265)	(2,995)	(98)	2,584
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	6,083	1,009	261	48	7,401
Unfunded	(141)	(1,274)	(3,256)	(146)	(4,817)
	5,942	(265)	(2,995)	(98)	2,584
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(17,183)	(4,250)	(1,746)	(861)	(24,040)
Unfunded	(141)	(1,274)	(3,256)	(146)	(4,817)
	(17,324)	(5,524)	(5,002)	(1,007)	(28,857)

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-employment benefit plans are included in the benefit obligation. Following the closure of the primary UK pension plan, current service cost in the UK consists of $38 million of costs of administering that plan and $10 million of current service cost from the remaining small worldwide plans administered and reported through the UK.
b Past service costs predominantly reflect minor plan changes in France. Settlements represent changes in small worldwide plans administered and reported throughout the UK.
c The benefit payments amount shown above comprises $1,907 million benefits and $352 million settlements relating to the buy-out in Canada, plus $57 million of plan expenses incurred in the administration of the benefit.
d The benefit obligation for the US is made up of $4,428 million for pension liabilities and $1,096 million for other post-employment benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $3,086 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 189.

24. Pensions and other post-employment benefits – continued

					$ million
					2023
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	44	156	47	21	268
Past service cost[b]	4	–	5	(2)	7
Settlement[b]	–	–	–	3	3
Operating charge (credit) relating to defined benefit plans	48	156	52	22	278
Payments to defined contribution plans	132	158	7	36	333
Total operating charge (credit)	180	314	59	58	611
Interest income on plan assets[a]	(1,259)	(274)	(78)	(56)	(1,667)
Interest on plan liabilities	869	297	194	66	1,426
Other finance (income) expense	(390)	23	116	10	(241)
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	(677)	45	82	28	(522)
Change in financial assumptions underlying the present value of the plan liabilities	(649)	28	(508)	(24)	(1,153)
Change in demographic assumptions underlying the present value of the plan liabilities	(230)	(5)	8	–	(227)
Experience gains and losses arising on the plan liabilities	(320)	45	(84)	(1)	(360)
Remeasurements recognized in other comprehensive income	(1,876)	113	(502)	3	(2,262)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	17,480	5,880	4,799	1,343	29,502
Exchange adjustments	1,056	–	215	30	1,301
Operating charge relating to defined benefit plans	48	156	52	22	278
Interest cost	869	297	194	66	1,426
Contributions by plan participants	6	–	2	5	13
Benefit payments (funded plans)[c]	(1,071)	(262)	(79)	(81)	(1,493)
Benefit payments (unfunded plans)[c]	(8)	(166)	(230)	(25)	(429)
Reclassified as assets held for sale	–	–	–	(14)	(14)
Remeasurements	1,199	(68)	584	25	1,740
Benefit obligation at 31 December[a d]	19,579	5,837	5,537	1,371	32,324
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	25,047	5,417	1,877	1,186	33,527
Exchange adjustments	1,462	–	81	39	1,582
Interest income on plan assets[a e]	1,259	274	78	56	1,667
Contributions by plan participants	6	–	2	5	13
Contributions by employers (funded plans)	20	–	11	11	42
Benefit payments (funded plans)[c]	(1,071)	(262)	(79)	(81)	(1,493)
Remeasurements[e]	(677)	45	82	28	(522)
Fair value of plan assets at 31 December[f]	26,046	5,474	2,052	1,244	34,816
Surplus (deficit) at 31 December	6,467	(363)	(3,485)	(127)	2,492
Represented by					
Asset recognized	6,631	1,133	120	64	7,948
Liability recognized	(164)	(1,496)	(3,605)	(191)	(5,456)
	6,467	(363)	(3,485)	(127)	2,492
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	6,631	1,133	104	29	7,897
Unfunded	(164)	(1,496)	(3,589)	(156)	(5,405)
	6,467	(363)	(3,485)	(127)	2,492
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(19,415)	(4,341)	(1,948)	(1,215)	(26,919)
Unfunded	(164)	(1,496)	(3,589)	(156)	(5,405)
	(19,579)	(5,837)	(5,537)	(1,371)	(32,324)

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-employment benefit plans are included in the benefit obligation. Following the closure of the primary UK pension plan, current service cost in the UK consists of $34 million of costs of administering that plan and $10 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. There was also a $5 million past service cost in France relating to statutory retirement age changes. Settlements represent charges for special termination benefits arising as a result of early retirements.

c The benefit payments amount shown above comprises $1,858 million benefits and $10 million settlements, plus $54 million of plan expenses incurred in the administration of the benefit.

d The benefit obligation for the US is made up of $4,527 million for pension liabilities and $1,310 million for other post-employment benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $3,393 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 189.

24. Pensions and other post-employment 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

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-employment benefit plans are included in the benefit obligation. Following the closure of the primary UK pension plan, 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.

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 2024 for the group's pensions and other post-employment benefit expense would have had the effects shown in the tables below. The effects shown for the expense in 2025 comprise the total of current service cost and net finance income or expense.

						$ million
						One percentage point
		UK		**US**		**Eurozone**
	Increase	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
Discount rate[a]						
Effect on expense in 2025	**(180)**	**162**	**(41)**	**46**	**(11)**	**7**
Effect on obligation at 31 December 2024	**(1,817)**	**2,219**	**(411)**	**578**	**(567)**	**691**
Inflation rate[b]						
Effect on expense in 2025	**81**	**(77)**	**7**	**(6)**	**32**	**(26)**
Effect on obligation at 31 December 2024	**1,460**	**(1,390)**	**38**	**(32)**	**532**	**(460)**

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 2025	**32**	**3**	**9**
Effect on obligation at 31 December 2024	**582**	**54**	**196**

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 2024 are as follows:

					$ million
Estimated future benefit payments	**UK**	**US**	**Eurozone**	**Other**	**Total**
2025	**1,081**	**464**	**305**	**80**	**1,930**
2026	**1,107**	**452**	**295**	**76**	**1,930**
2027	**1,127**	**453**	**293**	**76**	**1,949**
2028	**1,140**	**443**	**289**	**77**	**1,949**
2029	**1,160**	**446**	**284**	**77**	**1,967**
2030 - 2034	**5,892**	**2,260**	**1,317**	**399**	**9,868**
					Years
Weighted average duration	**11.7**	**8.8**	**13.3**	**12.5**	

25. Cash and cash equivalents

		$ million
	2024	2023
Cash	16,414	16,683
Triparty repos and term bank deposits	14,453	9,788
Other cash equivalents	8,337	6,559
	39,204	33,030

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 2024 includes $4,844 million (2023 $5,282 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 $5,774 million (2023 $7,174 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
			2024			2023
	Current	Non-current	Total	Current	Non-current	Total
Borrowings	4,474	55,073	59,547	3,284	48,670	51,954

The main elements of current borrowings are the current portion of long-term borrowings that is due to be repaid in the next 12 months of $3,793 million (2023 $2,688 million) and issued commercial paper of $500 million (2023 $456 million). Finance debt does not include accrued interest of $585 million (2023 $495 million), which is reported within other payables.

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

			Fixed rate debt		Floating rate debt	Total
	Weighted average interest rate %	Weighted average time for which rate is fixed Years	Amount $ million	Weighted average interest rate %	Amount $ million	Amount $ million
						2024
US dollar	4	8	41,145	5	17,847	58,992
Other currencies	6	3	396	6	159	555
			41,541		18,006	59,547
						2023
US dollar	4	13	33,511	8	18,134	51,645
Other currencies	6	7	205	10	104	309
			33,716		18,238	51,954

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 2024, 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
		2024		2023
	Fair value	Carrying amount	Fair value	Carrying amount
Short-term borrowings	681	681	596	596
Long-term borrowings	54,285	58,866	48,199	51,358
Total finance debt	54,966	59,547	48,795	51,954

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-IFRS 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 2024, gearing was 22.7% (2023 19.7%).

		$ million
At 31 December	**2024**	2023
Finance debt	**59,547**	51,954
Less: fair value asset (liability) of hedges related to finance debt[a]	**(2,654)**	(1,988)
	62,201	53,942
Less: cash and cash equivalents	**39,204**	33,030
Net debt	**22,997**	20,912
Total equity	**78,318**	85,493
Gearing	**22.7%**	19.7%

a Derivative financial instruments entered into for the purpose of managing foreign currency exchange risk associated with net debt with a fair value liability position of $166 million (2023 liability of $73 million) are not included in the calculation of net debt shown above as hedge accounting was not applied for these instruments.

Certain subsidiaries in the group have externally imposed capital requirements and have been in compliance with these requirements throughout the year.

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 2024	**51,954**	**2,978**	**11,121**	**30**	**66,083**
Exchange adjustments	**(39)**	**—**	**(272)**	**(1)**	**(312)**
Net financing cash flow	**4,761**	**(27)**	**(2,833)**	**(14)**	**1,887**
Fair value (gains) losses	**(840)**	**1,162**	**—**	**—**	**322**
New and remeasured leases/joint operations payables	**—**	**—**	**3,441**	**24**	**3,465**
Other movements[b]	**3,711**	**—**	**543**	**(2)**	**4,252**
At 31 December 2024	**59,547**	**4,113**	**12,000**	**37**	**75,697**
At 1 January 2023	46,944	5,312	8,549	42	60,847
Exchange adjustments	33	—	132	1	166
Net financing cash flow	3,040	(213)	(2,560)	(22)	245
Fair value (gains) losses	1,389	(2,065)	—	—	(676)
New and remeasured leases/joint operations payables	—	—	4,956	10	4,966
Other movements[c]	548	(56)	44	(1)	535
At 31 December 2023	51,954	2,978	11,121	30	66,083

a Currency swaps include cross currency interest rate swaps.
b Includes $3,726 million of finance debt and $585 million of lease liabilities acquired as part of the Lightsource bp and bp Bunge Bioenergia business combinations.
c Includes $545 million of finance debt acquired as part of the TravelCenters of America business combination.

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 $922 million (2023 $746 million) at the balance sheet date for shares repurchased between the end of the reporting period and 11 February 2025. $7,127 million (2023 $7,918 million) is included in financing activities 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 8 years (2023 7 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
	2024	2023
Undiscounted lease liability cash flows due:		
Within 1 year	**3,237**	3,038
1 to 2 years	**2,418**	2,177
2 to 3 years	**1,798**	1,386
3 to 4 years	**1,394**	1,139
4 to 5 years	**1,099**	947
5 to 10 years	**3,039**	3,045
Over 10 years	**1,283**	1,348
	14,268	13,080
Impact of discounting	**(2,268)**	(1,959)
Lease liabilities at 31 December	**12,000**	11,121
Of which – current	**2,660**	2,650
– non-current	**9,340**	8,471

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 2024 is $5,311 million (2023 $5,507 million). The majority of this future commitment relates to the floating LNG vessel to service the Greater Tortue Ahmeyim project from 2025.

		$ million
	2024	2023
Total cash outflow for amounts included in lease liabilities	**3,283**	2,904
Expense for variable payments not included in the lease liability[a]	**45**	27
Short-term lease expense[a]	**499**	657
Additions to right-of-use assets in the period	**3,781**	5,015

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 2024	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**	**1,431**	**–**	**1,457**
Loans		**1,807**	**377**	**–**	**2,184**
Trade and other receivables	20	**27,148**	**–**	**–**	**27,148**
Derivative financial instruments	30	**–**	**21,226**	**–**	**21,226**
Cash and cash equivalents	25	**32,547**	**6,657**	**–**	**39,204**
Financial liabilities					
Trade and other payables	22	**(61,298)**	**–**	**–**	**(61,298)**
Derivative financial instruments	30	**–**	**(20,224)**	**(2,655)**	**(22,879)**
Accruals		**(7,397)**	**–**	**–**	**(7,397)**
Lease liabilities	28	**(12,000)**	**–**	**–**	**(12,000)**
Finance debt	26	**(59,547)**	**–**	**–**	**(59,547)**
		(78,714)	**9,467**	**(2,655)**	**(71,902)**

At 31 December 2023	Note	Measured at amortized cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount ($ million)
Financial assets					
Other investments	18	26	3,006	–	3,032
Loans		1,725	457	–	2,182
Trade and other receivables	20	31,354	–	–	31,354
Derivative financial instruments	30	–	22,444	119	22,563
Cash and cash equivalents	25	27,804	5,226	–	33,030
Financial liabilities					
Trade and other payables	22	(65,516)	–	–	(65,516)
Derivative financial instruments	30	–	(13,545)	(2,107)	(15,652)
Accruals		(7,837)	–	–	(7,837)
Lease liabilities	28	(11,121)	–	–	(11,121)
Finance debt	26	(51,954)	–	–	(51,954)
		(75,519)	17,588	(1,988)	(59,919)

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

Information on gains and losses on derivative financial assets and financial liabilities classified as measured at fair value through profit or loss is provided in the derivative gains and losses section of Note 30. Fair value gains and losses related to other assets and liabilities classified as measured at fair value through profit or loss totalled a net gain of $1 million (2023 net loss of $11 million and 2022 net loss of $238 million). Dividend income of $24 million (2023 $18 million and 2022 $14 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 supply, 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 supply, 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 supply, trading and shipping business and are also underpinned by the compliance, control and risk management infrastructure common to the activities of bp's supply, 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 supply, 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 supply, 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 supply, 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 risk managed trading positions 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. Risk managed trading activity is subject to value-at-risk and other limits for each trading activity and the aggregate of

29. Financial instruments and financial risk factors – continued

all trading activity. The calculation of potential changes in value within the risk managed 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 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 risk managed trading positions at 31 December 2024 was $42 million (2023 $26 million) whereas the average value-at-risk measure for the period was $35 million (2023 $49 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 not risk managed and for which value-at-risk techniques are not appropriate.

(ii) Foreign currency exchange risk

Since bp has global operations, fluctuations in foreign currency exchange rates can have a significant effect on the group's reported results and future expenditure commitments. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates and translation differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the group's reported results. The main underlying economic currency of the group's cash flows is the US dollar. This is because bp's major product, oil, is priced internationally in US dollars. bp's foreign currency exchange management policy is to limit economic and material transactional exposures arising from currency movements against the US dollar. The group co-ordinates the handling of foreign currency exchange risks centrally, by netting off naturally-occurring opposite exposures wherever possible and then managing any material residual foreign currency exchange risks.

Most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2024, the total foreign currency borrowings not swapped into US dollars amounted to $555 million (2023 $309 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 2024 the most significant open contracts in place were for USD equivalent amounts of $92 million sterling (2023 $296 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 2024 was 30% of total finance debt outstanding (2023 35%). The weighted average interest rate on finance debt at 31 December 2024 was 5% (2023 5%) and the weighted average maturity of fixed rate debt was eight years (2023 thirteen 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 of $18,006 million (2023 $18,238 million) (see Note 26) were to have changed by one percentage point on 1 January 2025, it is estimated that the group's finance costs for 2025 would change by approximately $180 million (2023 $182 million).

(b) Credit risk

Credit risk is the risk that a customer or counterparty to a financial instrument will fail to perform or fail to pay amounts due causing financial loss to the group and arises from cash and cash equivalents, derivative financial instruments and deposits with financial institutions and principally from credit exposures to customers relating to outstanding receivables. Credit exposure also exists in relation to guarantees issued by group companies under which the outstanding exposure incremental to that recognized on the balance sheet at 31 December 2024 was $655 million (2023 $1,655 million) in respect of liabilities of joint ventures and associates and $585 million (2023 $598 million) in respect of liabilities of other third parties. An amount of $146 million (2023 $201 million) is recorded as a liability at 31 December 2024 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 2024, the group had in place credit enhancements designed to mitigate approximately $9.2 billion (2023 $12.0 billion) of credit risk of which approximately $8.2 billion (2023 $10.7 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 in the table below.

		%
As at 31 December	**2024**	2023
AAA to AA-	**12 %**	7 %
A+ to A-	**50 %**	59 %
BBB+ to BBB-	**16 %**	15 %
BB+ to BB-	**10 %**	7 %
B+ to B-	**8 %**	4 %
CCC+ and below	**4 %**	8 %

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.

				Related amounts not set off in the balance sheet		$ million
At 31 December 2024	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the balance sheet	Master netting arrangements	Cash collateral (received) pledged	Net amount
Derivative assets	**23,779**	**(2,553)**	**21,226**	**(5,624)**	**(362)**	**15,240**
Derivative liabilities	**(25,432)**	**2,553**	**(22,879)**	**5,624**	**294**	**(16,961)**
Trade and other receivables	**17,832**	**(9,445)**	**8,387**	**(1,532)**	**(206)**	**6,649**
Trade and other payables	**(20,289)**	**9,445**	**(10,844)**	**1,532**	**12**	**(9,300)**
At 31 December 2023						
Derivative assets	25,188	(2,625)	22,563	(3,436)	(1,245)	17,882
Derivative liabilities	(18,277)	2,625	(15,652)	3,436	263	(11,953)
Trade and other receivables	17,867	(7,789)	10,078	(1,141)	(633)	8,304
Trade and other payables	(16,284)	7,789	(8,495)	1,141	44	(7,310)

(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 letters of credit (LCs) 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 $12,130 million (2023 $13,180 million), allowing LCs to be issued for a maximum 24-month duration. The facilities are held with 16 international banks.

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 2024, a portion of the group's trade payables which were subject to the LC 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 payment terms were shorter.

The group sometimes uses promissory notes to pay its suppliers and other counterparties. This is primarily done to facilitate the counterparty accelerating its cash inflow without also accelerating the group's related cash outflow. For instance, if a supplier to the group's supply, trading and shipping business would like prepayment or early-payment for a supply of goods, the group may issue a promissory note (payable at a future date) in favour of that supplier on the supplier's desired cash inflow date, which that supplier can then convert to cash by selling it to a finance provider on the same-day. The majority of promissory notes the group issues accrue interest on the principal amount of the note at a fixed rate stated on the note from issuance to maturity. This is done to give the supplier or other counterparty certainty about the amount they will receive when they sell the note. It also gives the group flexibility to select the maturity date of the note without that impacting the net present value of the note on its issuance date. The maturity date the group selects for any promissory note that is for the purchase of goods by its supply and trading business will be no more than 60 days after the group takes (or expects to take) title to those goods.

A portion of the group's trade payables form part of a reverse factoring arrangement with select suppliers.

Suppliers' participation in the reverse factoring arrangement is voluntary. Suppliers that participate have the option to receive early payment on invoices from the group's external finance provider. If suppliers choose to receive early payment, they pay a fee to the finance provider. If they opt not to receive early payment, they will pay no fee to the finance provider and will be paid the full invoice amount on the invoice due date. The group provides data about invoices subject to the arrangement directly to the finance provider. This data includes the invoice due date and the maturity date for each invoice. The invoice due date is the date the supplier would have been entitled to receive payment from the group had the invoice not been made subject to the reverse factoring arrangement. The maturity date, which is the date the group will settle that invoice by paying the finance provider, will, in some cases, be the same as the invoice due date. In other cases, it will be a date selected by the group that is no more than 60 days after the group has taken title to the goods to which the invoice relates. If the group selects a maturity date that is after the invoice due date, the group pays the finance provider a fee.

Management does not consider the reverse factoring arrangement to result in excessive concentrations of liquidity risk, in part because the finance provider has the option to (and does) sub-participate portions of the financings to other finance providers. The arrangements have been established for a variety of reasons, including to ease the administrative burden of managing high volumes of invoices from some suppliers, to facilitate some suppliers having the option to accelerate when they receive payment or, often at a lower cost than that supplier's usual cost of borrowing, and, in some cases, to manage the working capital and reduce volatility in cash flow of the group's supply and trading business. The group has not derecognised the original trade payables relating to the arrangements because the original liability is not substantially modified on entering into the arrangements.

29. Financial instruments and financial risk factors – continued

Additional information about the group's trade payables that are subject to supplier finance arrangements is provided in the table below.

	2024		
	Letters of Credit	Promissory Notes	Reverse Factoring Arrangements
Carrying amount of liabilities ($ million)			
Presented within trade and other payables[a]	**7,431**	**1,778**	**390**
of which suppliers have received payment from the financial institution[b]	**7,016**	**1,778**	**390**
Range of payment due dates (days)			
Liabilities that are part of the arrangement[b]	**8 to 57**	**30 to 60**	**30 to 60**
Trade payables that are not part of the arrangement	**6 to 60**	**6 to 60**	**6 to 60**

a Letters of credit, promissory notes and reverse factoring arrangements related to amounts presented within trade and other payables in 2023 were $10,066 million, $953 million and $nil respectively.
b The group applied transitional relief available under IAS 7 and has not provided comparative information in the first year of adoption.

The group does not provide any collateral to the external finance provider.

There were no material business combinations or foreign exchange differences that would affect the liabilities under the supplier finance arrangement in either period.

There were no significant non-cash changes in the carrying amount of financial liabilities subject to the supplier finance arrangements. The payments to the bank are included within operating cash flows because they continue to be part of the normal operating cycle of the group and their principal nature remains operating – i.e., payment for the purchase of goods and services.

If these facilities were not available, this could result in renegotiation of payment terms with suppliers such that settlement periods were shorter.

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

During 2024, $9 billion (2023 $6 billion) of long-term taxable bonds were issued with terms ranging from three to twelve years. In addition the group issued perpetual hybrid capital bonds and securities with a US dollar equivalent value of $4.3 billion (2023 $0.2 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 $39.2 billion at 31 December 2024 (2023 $33.0 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. As at 31 December 2024, the group had substantial amounts of undrawn borrowing facilities available, consisting of an undrawn committed $8.0 billion credit facility and $4.0 billion of standby facilities. $7.8 billion of the credit facility was available for one year and $0.2 billion was available for less than 1 year. $3.9 billion of the standby facilities were available for 3 years and $0.1 billion were available for 2 years. These facilities were unutilized and were held with 27 international banks. In January 2025, the committed credit facility and standby facilities were replaced by new borrowing facilities, consisting of an undrawn committed $8.0 billion credit facility and $4.0 billion of standby facilities. These new facilities are available for 5 years, are held with 33 international banks and borrowings via these facilities would be at pre-agreed rates

For further information on the group's sources and uses of cash see Liquidity and capital resources on page 316.

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.

								$ million
				2024				2023
	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	**53,663**	**6,071**	**4,402**	**2,490**	56,852	6,527	3,054	2,394
1 to 2 years	**1,670**	**260**	**4,716**	**2,217**	1,876	329	3,820	2,151
2 to 3 years	**1,177**	**150**	**6,449**	**1,947**	1,158	147	4,767	1,907
3 to 4 years	**1,139**	**130**	**5,649**	**1,678**	1,178	135	5,367	1,666
4 to 5 years	**1,138**	**125**	**3,928**	**1,447**	1,141	121	5,778	1,396
5 to 10 years	**3,889**	**375**	**17,301**	**4,877**	5,028	382	12,939	4,894
Over 10 years	**157**	**286**	**13,947**	**6,198**	136	196	14,586	6,890
	62,833	**7,397**	**56,392**	**20,854**	67,369	7,837	50,311	21,298

a 2024 includes $9,520 million (2023 $10,662 million) in relation to the Gulf of America oil spill, of which $8,383 million (2023 $9,520 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 $24,206 million at 31 December 2024 (2023 $24,120 million) to be received on the same day as the related cash outflows.

		$ million
Cash outflows for derivative financial instruments at 31 December	2024	2023
Within one year	**1,718**	2,071
1 to 2 years	**5,136**	1,718
2 to 3 years	**3,077**	5,136
3 to 4 years	**1,743**	3,077
4 to 5 years	**3,696**	1,743
5 to 10 years	**8,307**	6,708
Over 10 years	**2,486**	4,092
	26,163	24,545

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

30. Derivative financial instruments

In the ordinary 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 its 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.

				$ million
		2024		2023
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**343**	**(1,738)**	478	(1,511)
Oil price derivatives	**1,350**	**(1,071)**	1,859	(1,139)
Natural gas price derivatives	**11,533**	**(10,506)**	14,750	(6,708)
Power price derivatives	**7,905**	**(6,893)**	5,355	(4,187)
Other derivatives	**95**	**(16)**	2	—
	21,226	**(20,224)**	22,444	(13,545)
Cash flow hedges				
Currency forwards	**—**	**—**	—	(1)
	—	**—**	—	(1)
Fair value hedges				
Currency swaps	**—**	**(2,651)**	119	(2,102)
Interest rate swaps	**—**	**(4)**	—	(4)
	—	**(2,655)**	119	(2,106)
	21,226	**(22,879)**	22,563	(15,652)
Of which – current	**5,112**	**(4,347)**	12,583	(5,250)
– non-current	**16,114**	**(18,532)**	9,980	(10,402)

Derivatives held for trading

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

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

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

							$ million
							2024
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**197**	**19**	**10**	**7**	**7**	**103**	**343**
Oil price derivatives	**1,004**	**156**	**78**	**53**	**55**	**4**	**1,350**
Natural gas price derivatives	**2,337**	**923**	**628**	**556**	**503**	**6,586**	**11,533**
Power price derivatives	**1,571**	**990**	**627**	**426**	**396**	**3,895**	**7,905**
Other derivatives	**4**	**4**	**—**	**85**	**—**	**2**	**95**
	5,113	**2,092**	**1,343**	**1,127**	**961**	**10,590**	**21,226**

							$ million
							2023
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	95	31	38	33	28	253	478
Oil price derivatives	1,423	206	81	52	41	56	1,859
Natural gas price derivatives	8,705	1,412	625	458	426	3,124	14,750
Power price derivatives	2,339	961	513	360	250	932	5,355
Other derivatives	—	—	—	—	—	2	2
	12,562	2,610	1,257	903	745	4,367	22,444

30. Derivative financial instruments – continued

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

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2024
Currency derivatives	**(111)**	**(529)**	**(172)**	**(4)**	**(562)**	**(360)**	**(1,738)**
Oil price derivatives	**(975)**	**(65)**	**(16)**	**(6)**	**(9)**	**—**	**(1,071)**
Natural gas price derivatives	**(2,075)**	**(836)**	**(515)**	**(409)**	**(363)**	**(6,308)**	**(10,506)**
Power price derivatives	**(1,062)**	**(779)**	**(569)**	**(401)**	**(471)**	**(3,611)**	**(6,893)**
Other derivatives	**(6)**	**(1)**	**—**	**(9)**	**—**	**—**	**(16)**
	(4,229)	**(2,210)**	**(1,272)**	**(829)**	**(1,405)**	**(10,279)**	**(20,224)**

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2023
Currency derivatives	(341)	(3)	(405)	(166)	(7)	(589)	(1,511)
Oil price derivatives	(1,047)	(61)	(14)	(4)	(1)	(12)	(1,139)
Natural gas price derivatives	(2,126)	(796)	(473)	(348)	(293)	(2,672)	(6,708)
Power price derivatives	(1,692)	(666)	(413)	(306)	(227)	(883)	(4,187)
	(5,206)	(1,526)	(1,305)	(824)	(528)	(4,156)	(13,545)

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

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2024
Fair value of derivative assets							
Level 1	**157**	**35**	**7**	**2**	**—**	**—**	**201**
Level 2	**5,037**	**1,457**	**551**	**330**	**134**	**107**	**7,616**
Level 3	**1,516**	**1,175**	**948**	**839**	**858**	**10,626**	**15,962**
	6,710	**2,667**	**1,506**	**1,171**	**992**	**10,733**	**23,779**
Less: netting by counterparty	**(1,597)**	**(575)**	**(163)**	**(44)**	**(31)**	**(143)**	**(2,553)**
	5,113	**2,092**	**1,343**	**1,127**	**961**	**10,590**	**21,226**
Fair value of derivative liabilities							
Level 1	**(124)**	**(20)**	**(7)**	**(2)**	**—**	**—**	**(153)**
Level 2	**(4,491)**	**(1,868)**	**(625)**	**(189)**	**(717)**	**(289)**	**(8,179)**
Level 3	**(1,211)**	**(897)**	**(803)**	**(682)**	**(719)**	**(10,133)**	**(14,445)**
	(5,826)	**(2,785)**	**(1,435)**	**(873)**	**(1,436)**	**(10,422)**	**(22,777)**
Less: netting by counterparty	**1,597**	**575**	**163**	**44**	**31**	**143**	**2,553**
	(4,229)	**(2,210)**	**(1,272)**	**(829)**	**(1,405)**	**(10,279)**	**(20,224)**
Net fair value	**884**	**(118)**	**71**	**298**	**(444)**	**311**	**1,002**

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2023
Fair value of derivative assets							
Level 1	98	41	11	1	—	—	151
Level 2	12,802	1,857	557	236	124	130	15,706
Level 3	1,765	1,063	784	699	638	4,263	9,212
	14,665	2,961	1,352	936	762	4,393	25,069
Less: netting by counterparty	(2,103)	(351)	(95)	(33)	(17)	(26)	(2,625)
	12,562	2,610	1,257	903	745	4,367	22,444
Fair value of derivative liabilities							
Level 1	(70)	(44)	(11)	(1)	—	—	(126)
Level 2	(6,051)	(1,127)	(844)	(365)	(93)	(500)	(8,980)
Level 3	(1,188)	(706)	(545)	(491)	(452)	(3,682)	(7,064)
	(7,309)	(1,877)	(1,400)	(857)	(545)	(4,182)	(16,170)
Less: netting by counterparty	2,103	351	95	33	17	26	2,625
	(5,206)	(1,526)	(1,305)	(824)	(528)	(4,156)	(13,545)
Net fair value	7,356	1,084	(48)	79	217	211	8,899

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 2024	**107**	**599**	**(120)**	**219**	**2**	**807**
Gains (losses) recognized in the income statement	**(26)**	**(90)**	**129**	**(193)**	**—**	**(180)**
Purchases	**—**	**—**	**31**	**—**	**—**	**31**
Settlements	**(38)**	**(100)**	**(377)**	**(14)**	**—**	**(529)**
Transfers out of level 3	**(13)**	**(15)**	**31**	**—**	**—**	**3**
Net fair value of contracts at 31 December 2024	**30**	**394**	**(306)**	**12**	**2**	**132**
Deferred day-one gains (losses)						**1,385**
Derivative asset (liability)						**1,517**

						$ million
	Oil price	Natural gas price	Power price	Currency	Other	Total
Fair value contracts at 1 January 2023	28	905	(524)	61	44	514
Gains (losses) recognized in the income statement	79	19	379	161	29	667
Settlements	13	(320)	86	(3)	(71)	(295)
Transfers out of level 3	(13)	(5)	(61)	—	—	(79)
Net fair value of contracts at 31 December 2023	107	599	(120)	219	2	807
Deferred day-one gains (losses)						1,341
Derivative asset (liability)						2,148

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2024 was a $193 million loss (2023 $631 million gain related to derivatives still held at 31 December 2023).

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 $9,726 million (2023 $19,786 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. 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 2024, there were no material gains or losses recorded on the associated derivative positions. For the year ended 31 December 2023, there were material gains recognized on the associated derivative positions due to the movement in the underlying commodity prices. . For additional information, details of management's internal measure of performance are given in the Group Performance Report on page 24 and on page 314.

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 $404 million (2023 $632 million net gain and 2022 $1,280 million net loss). 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 2024, 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 2024			
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	–	–	–
Commodity price risk			
Highly probable forecast sales	**155**	**(155)**	–
At 31 December 2023			
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	1	(1)	–
Commodity price risk			
Highly probable forecast sales	1,065	(1,065)	–

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		
At 31 December 2024	$ million	$ million	$ million	mmBtu
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	**–**	**–**	**95**	
Commodity price risk				
Highly probable forecast sales	**–**	**–**		**(209)**
At 31 December 2023				
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	–	(1)	318	
Commodity price risk				
Highly probable forecast sales	–	–		(392)

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 2024 and 2023 relating to highly probable forecast capital expenditure matures within 12 months of the relevant balance sheet date. All of the nominal amount of hedging instruments at 31 December 2024 and 31 December 2023 relating to highly probable forecast sales matures within 12 months of the relevant balance sheet date.

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			
	2024		2023	
At 31 December	**Forecast capital expenditure**	**Forecast sales**	Forecast capital expenditure	Forecast sales
Sterling/US dollar	**1.25**		1.27	
Euro/US dollar	**1.04**		1.11	
Henry Hub $/mmBtu		**3.38**		4.02

Fair value hedges

At 31 December 2024, 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, Australian dollar, Japanese yen, 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. 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
At 31 December 2024	Change in fair value of hedging instrument used to calculate ineffectiveness	Change in fair value of hedged item used to calculate ineffectiveness	Hedge ineffectiveness recognized in profit or (loss)
Fair value hedges			
Interest rate risk on finance debt	**—**	**1**	**(1)**
Interest rate and foreign currency risk on finance debt	**927**	**(772)**	**(155)**
At 31 December 2023			
Fair value hedges			
Interest rate risk on finance debt	—	—	—
Interest rate and foreign currency risk on finance debt	(1,417)	1,356	61

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		
At 31 December 2024	Assets	Liabilities	Nominal amounts of hedging instruments
Fair value hedges			
Interest rate risk on finance debt	**—**	**(4)**	**132**
Interest rate and foreign currency risk on finance debt	**—**	**(2,651)**	**15,887**
At 31 December 2023			
Fair value hedges			
Interest rate risk on finance debt	—	(4)	387
Interest rate and foreign currency risk on finance debt	119	(2,102)	16,862

All hedging instruments are presented within derivative financial instruments on the group balance sheet and are categorized within level 2 of the fair value hierarchy. 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 2024	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	**—**	**132**	**—**	**—**	**—**	**—**	**—**	**132**
Interest rate and foreign currency risk on finance debt	**1,614**	**1,819**	**1,346**	**1,627**	**1,047**	**6,521**	**1,913**	**15,887**
At 31 December 2023								
Fair value hedges								
Interest rate risk on finance debt	239	—	148	—	—	—	—	387
Interest rate and foreign currency risk on finance debt	1,857	1,716	1,933	1,441	1,741	4,164	4,010	16,862

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		**2024**		2023
	Interest rate swaps	**Cross-currency interest rate swaps**	Interest rate swaps	Cross-currency interest rate swaps
Interest rate	**5.45 %**	**6.34 %**	3.49 %	7.35 %
Sterling/US dollar		**1.28**		1.27
Euro/US dollar		**1.13**		1.13
Canadian dollar/US dollar		**0.78**		0.78
Australian dollar/ US dollar		**0.67**		—
Japanese Yen/ US dollar		**0.01**		—
Swiss Franc/US dollar		**1.18**		—

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 2024	Liabilities	Assets	Liabilities	Discontinued hedges
Fair value hedges				
Interest rate risk on finance debt	**(156)**	**3**	**—**	**(160)**
Interest rate and foreign currency risk on finance debt	**(16,295)**	**1,017**	**—**	**143**
At 31 December 2023				
Fair value hedges				
Interest rate risk on finance debt	(426)	4	—	(237)
Interest rate and foreign currency risk on finance debt	(16,834)	1,512	—	—

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	Interest rate and foreign currency risk on finance debt	Total
At 1 January 2024	14	529	(182)	361
Recognized in other comprehensive income				
Cash flow hedges marked to market	(1)	155	—	154
Cash flow hedges reclassified to the income statement - hedged item affected profit or loss	—	(686)	—	(686)
Costs of hedging marked to market	—	—	(2)	(2)
Costs of hedging reclassified to the income statement	—	—	(2)	(2)
	(1)	(531)	(4)	(536)
Cash flow hedges transferred to the balance sheet	(10)	—	—	(10)
At 31 December 2024	3	(2)	(186)	(185)

				$ million
	Cash flow hedge reserve		Costs of hedging reserve	
	Highly probable forecast capital expenditure	Highly probable forecast sales	Interest rate and foreign currency risk on finance debt	Total
At 1 January 2023	—	(108)	(104)	(212)
Recognized in other comprehensive income				
Cash flow hedges marked to market	15	1,065	—	1,080
Cash flow hedges reclassified to the income statement - hedged item affected profit or loss	—	(428)	—	(428)
Costs of hedging marked to market	—	—	(67)	(67)
Costs of hedging reclassified to the income statement	—	—	(11)	(11)
	15	637	(78)	574
Cash flow hedges transferred to the balance sheet	(1)	—	—	(1)
At 31 December 2023	14	529	(182)	361

All of the cash flow hedge reserve balances at 31 December 2024 and amounts reclassified from these cash flow hedge reserves into profit or loss during the year relate to continuing hedge relationships. The amounts reclassified 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:

	2024		2023		2022	
Issued	Shares thousand	$ million	Shares thousand	$ million	Shares thousand	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**17,900,800**	**4,475**	19,097,783	4,774	20,778,082	5,194
Issue of new shares for employee share-based payment plans	**—**	**—**	66,000	17	55,000	14
Issue of new shares – other[b]	**—**	**—**	—	—	165,105	41
Repurchase of ordinary share capital	**(1,238,335)**	**(310)**	(1,262,983)	(316)	(1,900,404)	(475)
At 31 December	**16,662,465**	**4,165**	17,900,800	4,475	19,097,783	4,774
		4,186		4,496		4,795

a The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.
b 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.

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 2024 the company repurchased 1,238 million (2023 1,263 million) ordinary shares for a total consideration of $7,127 million (2023 $7,918 million) , including transaction costs of $38 million (2023 $43 million). All shares purchased were for cancellation. The repurchased shares represented 7.4% of ordinary share capital. A further 176 million ordinary shares were repurchased between the end of the reporting period and 14 February 2025, the latest practicable date before the completion of these financial statements, for a total cost of $927 million of which $922 million has been accrued at 31 December 2024. The number of shares in issue is reduced when shares are repurchased.

Treasury shares[a]

	2024		2023		2022	
	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,077,079**	**271**	1,124,927	281	1,137,457	283
Purchases for settlement of employee share plans	**8,302**	**2**	24,688	6	14,150	4
Issue of new shares for employee share-based payment plans	**—**	**—**	71,039	19	55,000	14
Shares re-issued for employee share-based payment plans	**(273,360)**	**(69)**	(143,575)	(35)	(81,680)	(20)
At 31 December	**812,021**	**204**	1,077,079	271	1,124,927	281
Of which – shares held in treasury by bp	**481,474**	**121**	726,339	183	940,571	235
– shares held in ESOP trusts	**330,510**	**83**	350,704	88	184,356	46
– shares held by bp's US share plan administrator[b]	**37**	**—**	36	—	—	—

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 4.1% (2023 4.9% and 2022 5.0%) of the called-up ordinary share capital of the company.

During 2024, the movement in shares held in treasury by bp represented 1.4% (2023 1.1% and 2022 less than 0.5%) of the ordinary share capital of the company.

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32. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2024	**4,496**	**13,815**	**2,496**	**27,206**	**48,013**
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-employment benefit liability or asset	–	–	–	–	–
Remeasurements of equity investments	–	–	–	–	–
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	(310)	–	310	–	–
Share-based payments, net of tax[b]	–	216	–	–	216
Issue of perpetual hybrid bonds	–	–	–	–	–
Redemption of perpetual hybrid bonds	–	–	–	–	–
Payments on perpetual hybrid bonds	–	–	–	–	–
Transactions involving non-controlling interests, net of tax	–	–	–	–	–
At 31 December 2024	**4,186**	**14,031**	**2,806**	**27,206**	**48,229**

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2023	4,795	13,692	2,180	27,206	47,873
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	–	–	–	–	–
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-employment benefit liability or asset	–	–	–	–	–
Remeasurements of equity investments	–	–	–	–	–
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	(316)	–	316	–	–
Share-based payments, net of tax[b]	17	123	–	–	140
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	–
Issue of perpetual hybrid bonds	–	–	–	–	–
Payments on perpetual hybrid bonds	–	–	–	–	–
Transactions involving non-controlling interests, net of tax	–	–	–	–	–
At 31 December 2023	4,496	13,815	2,496	27,206	48,013

a Includes $942 million recycling of cumulative foreign exchange losses from reserves relating to the sale of bp's Türkiye ground fuels business to Petrol Ofisi, offset by movements in Pound Sterling against the US dollar.

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

32. Capital and reserves – continued

$ million

								Non-controlling interests		
Treasury shares	Foreign currency translation reserve	Investments in equity instruments	Cash flow hedges	Costs of hedging	Total fair value reserves	Profit and loss account	bp shareholders' equity	Hybrid bonds	Other interest	Total equity
(11,323)	**(1,920)**	**38**	**319**	**(183)**	**174**	**35,339**	**70,283**	**13,566**	**1,644**	**85,493**
–	**–**	**–**	**–**	**–**	**–**	**381**	**381**	**641**	**207**	**1,229**
–	**(276)**	**(1)**	**–**	**–**	**(1)**	**–**	**(277)**	**–**	**(87)**	**(364)**
–	**–**	**–**	**(406)**	**(4)**	**(410)**	**–**	**(410)**	**–**	**–**	**(410)**
–	**–**	**–**	**–**	**–**	**–**	**(12)**	**(12)**	**–**	**–**	**(12)**
–	**–**	**–**	**–**	**–**	**–**	**(1)**	**(1)**	**–**	**–**	**(1)**
–	**–**	**–**	**–**	**–**	**–**	**367**	**367**	**–**	**–**	**367**
–	**–**	**(40)**	**–**	**–**	**(40)**	**–**	**(40)**	**–**	**–**	**(40)**
–	**–**	**–**	**(1)**	**–**	**(1)**	**–**	**(1)**	**–**	**–**	**(1)**
–	**(276)**	**(41)**	**(407)**	**(4)**	**(452)**	**735**	**7**	**641**	**120**	**768**
–	**–**	**–**	**–**	**–**	**–**	**(5,018)**	**(5,018)**	**–**	**(375)**	**(5,393)**
–	**–**	**–**	**(10)**	**–**	**(10)**	**–**	**(10)**	**–**	**–**	**(10)**
–	**–**	**–**	**–**	**–**	**–**	**(7,302)**	**(7,302)**	**–**	**–**	**(7,302)**
2,293	**–**	**–**	**–**	**–**	**–**	**(1,426)**	**1,083**	**–**	**–**	**1,083**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
–	**–**	**–**	**–**	**–**	**–**	**(22)**	**(22)**	**4,352**	**–**	**4,330**
–	**–**	**–**	**–**	**–**	**–**	**9**	**9**	**(1,300)**	**–**	**(1,291)**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(610)**	**–**	**(610)**
–	**–**	**–**	**–**	**–**	**–**	**216**	**216**	**–**	**1,034**	**1,250**
(9,030)	**(2,196)**	**(3)**	**(98)**	**(187)**	**(288)**	**22,531**	**59,246**	**16,649**	**2,423**	**78,318**
(12,153)	(2,643)	–	(183)	(73)	(256)	34,732	67,553	13,390	2,047	82,990
–	–	–	–	–	–	15,239	15,239	586	55	15,880
–	728	–	–	–	–	–	728	–	26	754
–	–	–	488	(110)	378	–	378	–	–	378
–	–	–	–	–	–	(192)	(192)	–	–	(192)
–	–	–	–	–	–	(1,504)	(1,504)	–	–	(1,504)
–	–	38	–	–	38	–	38	–	–	38
–	–	–	15	–	15	–	15	–	–	15
–	728	38	503	(110)	431	13,543	14,702	586	81	15,369
–	–	–	–	–	–	(4,831)	(4,831)	–	(403)	(5,234)
–	–	–	(1)	–	(1)	–	(1)	–	–	(1)
–	–	–	–	–	–	(8,167)	(8,167)	–	–	(8,167)
830	–	–	–	–	–	(301)	669	–	–	669
–	–	–	–	–	–	1	1	–	–	1
–	–	–	–	–	–	(1)	(1)	176	–	175
–	(5)	–	–	–	–	–	(5)	(586)	–	(591)
–	–	–	–	–	–	363	363	–	(81)	282
(11,323)	(1,920)	38	319	(183)	174	35,339	70,283	13,566	1,644	85,493

32. Capital and reserves – continued

	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)[b]	–	–	–	–	–
Cash flow hedges and costs of hedging (including reclassifications)[c]	–	–	–	–	–
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-employment 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[a]	14	168	–	–	182
Issue of perpetual hybrid bonds	–	–	–	–	–
Payments on 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

a Movements in treasury shares relate to employee share-based payment plans.
b Following bp's decision to exit its shareholding in Rosneft on 27 February 2022, $10,372 million was reclassified to the income statement.
c Following bp's decision to exit its shareholding in Rosneft on 27 February 2022 $651 million was reclassified to the income statement.

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: Hybrid bonds	Non-controlling interests: Other interest	Total equity
(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

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 premium arising where the fair value of the consideration given is in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares where merger relief under the Companies Act applies.

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.

Investments in equity instruments

This reserve records the change in fair value of investments in equity instruments for which the group has elected to recognize fair value gains and losses in other comprehensive income.

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.

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. 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, perpetual subordinated hybrid securities and certain equity instruments with preferred distributions issued by group subsidiaries. The contractual terms of these instruments allow the group to defer coupon payments, equity distributions and repayment of principal indefinitely. However, the terms and conditions of each instrument stipulate the circumstances in which deferred payments and/or the principal amount of the instrument becomes payable. These circumstances, which include the announcement of a bp p.l.c. ordinary share or parity equity dividend distribution, are within the group's control.

Perpetual subordinated hybrid bonds are issued by BP Capital Markets p.l.c., a group subsidiary, in euro, sterling and US dollars. During the year BP Capital Markets p.l.c. voluntarily bought back $1.3 billion of the non-call 2025 4.375% US dollar hybrid bonds issued in 2020 and issued euro, sterling and US dollar hybrid bonds for a US dollar equivalent amount of $3.9 billion. Coupons on the new issuances are fixed for an initial period up to dates from 2030 to 2035 at rates of 4.375% to 6.45%. As at 31 December 2024 the total population of hybrid bonds include redemption options exercisable at the group's discretion from June 2025 to March 2035 (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 2035 at rates of 3.25% to 6.45% and reset to rates determined by the contractual terms of each instrument on certain dates thereafter. 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 swap the non-US dollar hybrid bonds to a USD floating interest rate up to their respective first call periods. Payments made to and profit attributed to these hybrid bonds in the year totalled $485 million (2023 $477 million) and $517 million (2023 $473 million) respectively. The amount of hybrid bonds included in non-controlling interests at the end of the year was $14.6 billion (2023 $12.1 billion).

Perpetual subordinated hybrid securities issued by group subsidiaries include $500 million issued during 2024, specifically earmarked to fund BP Alternative Energy Investments Ltd including the funding of Lightsource bp. Payments made to and profit attributed to perpetual hybrid securities in the year totalled $125 million (2023 $114 million) and $125 million (2023 $113 million) respectively. The amount of perpetual subordinated hybrid securities included within non-controlling interests at the end of the year was $2.0 billion (2023 $1.5 billion).

Equity instruments with preferred distributions issued by group subsidiaries include $1,330 million issued during 2024 comprising $500 million of proceeds from the sale of a 49% interest in a subsidiary that holds certain midstream assets offshore US; and $830 million of proceeds from the sale of a 25% non-controlling interest in BP Pipelines TAP Limited, the bp subsidiary that holds a 20% share in Trans Adriatic Pipeline AG. In both transactions, the group retains control over the ability to defer equity distributions which are not guaranteed, and investors have no right to redeem their shares other than in certain circumstances that are within the group's control. The amount associated with equity instruments with preferred distributions included within non-controlling interests at the end of the year was approximately $1.3 billion (2023 $0.3 billion).

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
			2024
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	**(288)**	**(76)**	**(364)**
Cash flow hedges (including reclassifications)	**(531)**	**125**	**(406)**
Costs of hedging (including reclassifications)	**(4)**	**–**	**(4)**
Share of items relating to equity-accounted entities, net of tax	**(12)**	**–**	**(12)**
Other	**–**	**(1)**	**(1)**
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-employment benefit liability or asset[a]	**(360)**	**727**	**367**
Remeasurements of equity investments	**(47)**	**7**	**(40)**
Cash flow hedges that will subsequently be transferred to the balance sheet	**(1)**	**–**	**(1)**
Other comprehensive income	**(1,243)**	**782**	**(461)**

			$ million
			2023
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	583	171	754
Cash flow hedges (including reclassifications)	637	(149)	488
Costs of hedging (including reclassifications)	(78)	(32)	(110)
Share of items relating to equity-accounted entities, net of tax	(192)	–	(192)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-employment benefit liability or asset	(2,262)	758	(1,504)
Remeasurements of equity investments	51	(13)	38
Cash flow hedges that will subsequently be transferred to the balance sheet	15	–	15
Other comprehensive income	(1,246)	735	(511)

			$ 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-employment 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

a 2024 includes a $658-million credit in respect of the reduction in the deferred tax liability on defined benefit pension plan surpluses following the reduction in the rate of the authorized surplus payments tax charge in the UK from 35% to 25%.

33. Contingent liabilities and legal proceedings

Contingent liabilities

There were contingent liabilities at 31 December 2024 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 (2023 $16 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 America oil spill

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

Legal proceedings

Proceedings relating to the Deepwater Horizon oil spill

Introduction

BP Exploration & Production Inc. (BPXP) was lease operator of Mississippi Canyon, Block 252 in the Gulf of America, 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 includes an exclusive remedy provision regarding class members pursuing exposure-based personal injury claims for later-manifested physical conditions (LMPCs). As of 31 December 2024, there were 26 pending lawsuits brought by class members claiming LMPCs.

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 620 cases in which the courts granted BPXP's motions for summary judgment). As of 31 December 2024, 38 cases remained pending in the district courts.

Non-US government lawsuits

Two class actions are pending in Mexican Federal District Courts against various bp group entities including BPXP and BP America Production Company by separate plaintiff classes. Although the two actions are separate, both broadly seek penalties, damages and compensation for alleged environmental, health and economic harm in Mexico as a result of the Incident. One of the actions also seeks an order requiring the bp defendants to repair alleged damage to Mexican waters and land.

bp has answered the complaints in both actions 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.

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

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 approximately 30 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. Defendants spent several years seeking to have the cases removed to federal courts, however Defendants' attempts were ultimately unsuccessful. Accordingly, the cases are proceeding in various state courts. As a group, the lawsuits generally remain at relatively early stages in the litigation process. 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 were named defendants in 17 of these cases. The lawsuits allege that the defendants' historical operations in oil and gas fields within the Louisiana onshore coastal zone failed to comply with state permits and/or were conducted without the required coastal use permits. The scope and scale of plaintiffs' damages demands are significant and unprecedented, including substantial remediation costs, natural resource (ecological impact) damages and the claimed costs for restoring coastal wetlands allegedly impacted by oil and gas 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 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. In 2024, the US Fifth Circuit issued a further final ruling rejecting "federal officer" jurisdiction in a subset of the removed cases contested on a related removal theory and remanded all such cases to state district court.

Following remand of the other lead removal case, Cameron Parish v. Auster, et. al., in which bp was the principal defendant, bp entered into a settlement agreement and release with the plaintiffs in late 2023 in respect of all state and local governmental claims arising within Cameron Parish. The terms of the settlement agreement and release are confidential and have not had and are not expected to have in the future, a significant effect on the company's financial position or profitability.

Atlantic Richfield Company, a bp affiliate, was a named defendant along with other oil & gas companies in a case, Plaquemines Parish v. Rozel, et al, set for trial in March 2025. A state trial court in December 2024 ruled in favour of Atlantic Richfield's motion for summary judgment and dismissed it from the case, but following a motion by plaintiffs for reconsideration, the court reversed its summary judgment ruling and reinstated Atlantic Richfield as a defendant. The plaintiffs' claims against Atlantic Richfield have been severed from the initial March 2025 trial date, and the court has yet to establish a new trial date for the plaintiffs' now separate claims against Atlantic Richfield.

No bp entity is a named defendant in any of the other active Louisiana Coastal restoration docket cases with a trial date, all of which remain in the early stages of litigation. 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, having been previously dismissed from a third.

While it is not possible to predict the outcomes of these novel 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
	2024	2023	2022
Total for all directors			
Emoluments	**8**	8	8
Amounts received under incentive schemes[a]	**5**	6	13
Total	**13**	14	21

[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 88.

Remuneration of directors and senior management

			$ million
	2024	2023	2022
Total for all senior management and non-executive directors			
Short-term employee benefits	**22**	31	31
Pensions and other post-employment benefits	**—**	—	—
Share-based payments[a]	**26**	12	31
Termination benefits	**3**	—	—
Total	**51**	43	62

[a] 2023 includes a reversal of $14 million relating to the lapse of Bernard Looney's outstanding share awards in prior years.

Senior management comprises members of the leadership team, see page 74 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-employment benefits

The amounts represent the estimated cost to the group of providing pensions and other post-employment 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 2024 to 14 February 2025.

35. Employee costs and numbers

Employee costs	2024	2023	2022
			$ million
Wages and salaries[a]	**8,601**	7,835	7,486
Social security costs	**1,032**	943	720
Share-based payments[b]	**1,088**	1,131	1,034
Pension and other post-employment benefit costs	**519**	370	576
	11,240	10,279	9,816

			2024			2023			2022
Average number of employees[c]	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
gas & low carbon energy	**900**	**4,400**	**5,300**	900	3,700	4,600	700	3,400	4,100
oil production & operations	**3,300**	**5,700**	**9,000**	3,100	5,500	8,600	3,000	5,700	8,700
customers & products[d e]	**27,500**	**38,000**	**65,500**	19,500	36,300	55,800	8,000	35,700	43,700
other businesses and corporate	**1,400**	**9,800**	**11,200**	1,400	9,000	10,400	1,300	8,500	9,800
	33,100	**57,900**	**91,000**	24,900	54,500	79,400	13,000	53,300	66,300

a Includes termination costs of $336 million (2023 $96 million and 2022 $27 million).
b The group provides certain employees with shares and share options as part of their remuneration packages. The majority of these share-based payment arrangements are equity-settled.
c Reported to the nearest 100.
d Includes 40,700 (2023 33,800 and 2022 23,300) service station staff.
e Includes 1,700 (2023 0 and 2022 0) agricultural, operational and seasonal workers in Brazil.

36. Auditor’s remuneration

Fees	2024	2023	2022
			$ million
The audit of the company annual accounts[a]	**40**	38	36
The audit of accounts of subsidiaries of the company	**17**	15	15
Total audit	**57**	53	51
Audit-related assurance services[b]	**4**	4	4
Total audit and audit-related assurance services	**61**	57	55
Non-audit and other assurance services	**4**	3	—
Services relating to bp pension plans	**1**	1	1
	66	61	56

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.

2024 includes $1.3 million of additional fees for 2023. 2023 includes $0.2 million of additional fees for 2022. 2022 includes $0.3 million of additional fees for 2021. 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 2024 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 $66 million (2023 $61 million and 2022 $56 million) is required to be presented as follows: audit $57 million (2023 $53 million and 2022 $51 million); other audit-related $4 million (2023 $4 million and 2022 $4 million); tax $nil (2023 $nil and 2022 $nil); and all other fees $5 million (2023 $4 million and 2022 $1 million).

37. Subsidiaries, joint arrangements and associates[a]

The more important subsidiaries, joint arrangements and associates of the group at 31 December 2024 and the group percentage of ordinary share capital (to nearest whole number) are set out below. The group's share of the assets and liabilities of the more important unincorporated joint arrangements are held by subsidiaries listed in the table below. Those subsidiaries held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of undertakings of the group is included in Note 14 in the parent company financial statements of BP p.l.c. which are filed with the Registrar of Companies in the UK, along with the group's annual report.

Subsidiaries	%	Country of incorporation	Principal activities
International			
BP Corporate Holdings Limited	100	England & Wales	Investment holding
BP Exploration Operating Company Limited	100	England & Wales	Exploration and production
*BP Gamma Holdings Limited	100	England & Wales	Investment holding
*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
*Castrol Group Holdings Limited	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
Germany			
BP Europa SE	100	Germany	Refining and marketing
Trinidad and Tobago			
BP Trinidad and Tobago LLC	70	US	Exploration and production
UK			
BP Capital Markets p.l.c.	100	England & Wales	Finance
Lightsource BP Renewable Energy Investments Limited	100	England & Wales	Solar
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	Bioenergy
BP Capital Markets America Inc.	100	US	Finance

Joint arrangements	%	Country of incorporation	Principal activities
Angola			
Azule Energy Holdings Limited	50	England & Wales	Exploration and production

a There were no important associates in the group at 31 December 2024.

38. Events after the reporting period

On 26 February 2025, bp announced a fundamentally reset strategy, with significant capital reallocation, and plans to drive improved performance, aimed at growing free cash flow, returns and long-term shareholder value. This strategy will see bp grow its upstream oil and gas business, focus its downstream business, and invest with increasing discipline into the transition. It builds on bp's distinct strengths and competitive advantages as an integrated energy company. There are no impacts on these financial statements related to the strategy announcements in accordance with IAS 10 'Events after the reporting period'.

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 318-326.

a See Note 1 - Investment in Rosneft.

Oil and natural gas exploration and production activities

									$ million
									2024
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
Capitalized costs at 31 December[a b]									
Gross capitalized costs									
Proved properties	29,781	–	72,248	8	14,427	18,756	42,709	6,504	184,433
Unproved properties	411	–	3,012	1,936	2,760	2,471	1,701	762	13,053
	30,192	–	75,260	1,944	17,187	21,227	44,410	7,266	197,486
Accumulated depreciation	24,269	–	44,067	1,602	13,450	20,373	27,528	5,506	136,795
Net capitalized costs	5,923	–	31,193	342	3,737	854	16,882	1,760	60,691
Costs incurred for the year ended 31 December[a b]									
Acquisition of properties									
Proved	–	–	52	–	–	–	–	–	52
Unproved	–	–	21	–	2	–	–	–	23
	–	–	73	–	2	–	–	–	75
Exploration and appraisal costs[c]	57	–	655	102	294	508	82	59	1,757
Development	629	–	3,829	–	661	1,334	1,363	137	7,953
Total costs	686	–	4,557	102	957	1,842	1,445	196	9,785
Results of operations for the year ended 31 December[a]									
Sales and other operating revenues[d]									
Third parties	182	–	1,859	–	1,090	2,094	4,515	1,888	11,628
Sales between businesses	2,762	–	13,035	–	163	–	7,410	362	23,732
	2,944	–	14,894	–	1,253	2,094	11,925	2,250	35,360
Exploration expenditure	1	–	463	97	137	188	55	33	974
Production costs	539	–	2,645	1	399	230	617	106	4,537
Production taxes	(4)	–	149	–	248	–	1,366	40	1,799
Other costs (income)[e]	(221)	(8)	2,455	23	47	49	(59)	116	2,402
Depreciation, depletion and amortization	1,234	–	4,394	3	1,206	543	3,116	477	10,973
Net impairments and (gains) losses on sale of businesses and fixed assets	1,058	14	(471)	(19)	(259)	2,312	(1)	(1)	2,633
	2,607	6	9,635	105	1,778	3,322	5,094	771	23,318
Profit (loss) before taxation[f]	337	(6)	5,259	(105)	(525)	(1,228)	6,831	1,479	12,042
Allocable taxes	195	(1)	1,194	(14)	(203)	291	5,003	557	7,022
Results of operations	142	(5)	4,065	(91)	(322)	(1,519)	1,828	922	5,020

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 America 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 and pre development studies, 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 $313-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 $460 million which is included in finance costs in the group income statement.

Oil and natural gas exploration and production activities – continued

									$ million
									2024
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Equity-accounted entities (bp share)									
Capitalized costs at 31 December[a b]									
Gross capitalized costs									
Proved properties	–	5,211	–	–	12,185	10,181	10,848	–	38,425
Unproved properties	–	705	–	–	130	344	–	–	1,179
	–	5,916	–	–	12,315	10,525	10,848	–	39,604
Accumulated depreciation	–	2,968	–	–	7,284	3,209	2,661	–	16,122
Net capitalized costs	–	2,948	–	–	5,031	7,316	8,187	–	23,482
Costs incurred for the year ended 31 December[a c d]									
Acquisition of properties[b]									
Proved	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	–	26	–	–	26
	–	–	–	–	–	26	–	–	26
Exploration and appraisal costs[c]	–	58	–	–	5	54	–	–	117
Development	–	761	–	–	821	1,105	901	–	3,588
Total costs	–	819	–	–	826	1,185	901	–	3,731
Results of operations for the year ended 31 December[a]									
Sales and other operating revenues[e]									
Third parties	–	1,943	–	–	1,967	2,692	1,854	–	8,456
Sales between businesses	–	–	–	–	–	–	–	–	–
	–	1,943	–	–	1,967	2,692	1,854	–	8,456
Exploration expenditure	–	51	–	–	–	8	–	–	59
Production costs	–	145	–	–	812	560	574	–	2,091
Production taxes	–	–	–	–	324	37	–	–	361
Other costs (income)	–	26	–	–	134	339	25	–	524
Depreciation, depletion and amortization	–	453	–	–	477	1,431	965	–	3,326
Net impairments and losses on sale of businesses and fixed assets	–	65	–	–	849	–	–	–	914
	–	740	–	–	2,596	2,375	1,564	–	7,275
Profit (loss) before taxation	–	1,203	–	–	(629)	317	290	–	1,181
Allocable taxes	–	931	–	–	(766)	198	120	–	483
Results of operations	–	272	–	–	137	119	170	–	698

a 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.
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 and pre development studies, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
d 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.
e Presented net of sales tax.

Oil and natural gas exploration and production activities – continued

$ million

2023

	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
Capitalized costs at 31 December[a b]									
Gross capitalized costs									
Proved properties	29,127	—	70,404	6	17,475	20,763	41,351	6,331	185,457
Unproved properties	369	—	3,057	1,917	2,565	2,739	1,691	737	13,075
	29,496	—	73,461	1,923	20,040	23,502	43,042	7,068	198,532
Accumulated depreciation	22,018	—	42,364	1,592	15,712	21,132	24,431	4,998	132,247
Net capitalized costs	7,478	—	31,097	331	4,328	2,370	18,611	2,070	66,285
Costs incurred for the year ended 31 December[a b]									
Acquisition of properties									
Proved	—	—	13	—	—	—	—	—	13
Unproved	—	—	51	—	2	6	—	—	59
	—	—	64	—	2	6	—	—	72
Exploration and appraisal costs[c]	123	—	356	123	114	270	145	100	1,231
Development	484	—	4,690	—	713	863	1,424	32	8,206
Total costs	607	—	5,110	123	829	1,139	1,569	132	9,509
Results of operations for the year ended 31 December[a]									
Sales and other operating revenues[d]									
Third parties	206	—	665	—	1,348	3,227	4,801	1,765	12,012
Sales between businesses	3,483	—	12,705	—	20	22	7,731	412	24,373
	3,689	—	13,370	—	1,368	3,249	12,532	2,177	36,385
Exploration expenditure	46	—	348	93	54	413	25	18	997
Production costs	477	—	2,382	2	360	232	588	111	4,152
Production taxes	13	—	136	—	229	—	1,357	44	1,779
Other costs (income)[e]	(171)	—	2,144	13	115	304	(35)	145	2,515
Depreciation, depletion and amortization	1,063	—	3,532	—	1,351	1,546	2,844	412	10,748
Net impairments and (gains) losses on sale of businesses and fixed assets	819	(18)	701	(100)	671	1,430	(1)	(4)	3,498
	2,247	(18)	9,243	8	2,780	3,925	4,778	726	23,689
Profit (loss) before taxation[f]	1,442	18	4,127	(8)	(1,412)	(676)	7,754	1,451	12,696
Allocable taxes	365	19	889	(3)	(565)	439	5,317	451	6,912
Results of operations	1,077	(1)	3,238	(5)	(847)	(1,115)	2,437	1,000	5,784

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 America 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 and pre development studies, 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 $287-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 $390 million which is included in finance costs in the group income statement.

Oil and natural gas exploration and production activities – continued

$ million

2023

	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Equity-accounted entities (bp share)									
Capitalized costs at 31 December[a b]									
Gross capitalized costs									
Proved properties	–	4,432	–	–	12,530	8,590	9,947	–	35,499
Unproved properties	–	652	–	–	125	372	–	–	1,149
	–	5,084	–	–	12,655	8,962	9,947	–	36,648
Accumulated depreciation	–	2,420	–	–	6,807	1,812	1,696	–	12,735
Net capitalized costs	–	2,664	–	–	5,848	7,150	8,251	–	23,913
Costs incurred for the year ended 31 December[a c d]									
Acquisition of properties[b]									
Proved	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–
Exploration and appraisal costs[c]	–	42	–	–	7	44	–	–	93
Development	–	584	–	–	687	844	942	–	3,057
Total costs	–	626	–	–	694	888	942	–	3,150
Results of operations for the year ended 31 December[a]									
Sales and other operating revenues[e]									
Third parties	–	2,159	–	–	2,070	2,550	1,716	–	8,495
Sales between businesses	–	–	–	–	–	–	–	–	–
	–	2,159	–	–	2,070	2,550	1,716	–	8,495
Exploration expenditure	–	41	–	–	–	44	–	–	85
Production costs	–	169	–	–	715	427	374	–	1,685
Production taxes	–	–	–	–	332	52	–	–	384
Other costs (income)	–	21	–	–	257	239	8	–	525
Depreciation, depletion and amortization	–	455	–	–	451	1,344	1,144	–	3,394
Net impairments and losses on sale of businesses and fixed assets	–	141	–	–	–	15	–	–	156
	–	827	–	–	1,755	2,121	1,526	–	6,229
Profit (loss) before taxation	–	1,332	–	–	315	429	190	–	2,266
Allocable taxes	–	1,124	–	–	127	173	117	–	1,541
Results of operations	–	208	–	–	188	256	73	–	725

a 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.
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 and pre development studies, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
d 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.
e Presented net of sales tax.

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[h]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Capitalized costs at 31 December[a b]										
Gross capitalized costs										
Proved properties	30,010	—	65,870	6	16,720	20,257	—	39,899	6,324	179,086
Unproved properties	397	—	2,976	1,875	2,507	2,535	—	1,622	659	12,571
	30,407	—	68,846	1,881	19,227	22,792	—	41,521	6,983	191,657
Accumulated depreciation	21,757	—	38,205	1,586	13,849	18,207	—	21,642	4,588	119,834
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 America 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 and pre development studies, 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.

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.

h An amendment has been made to correctly present offsetting movements in proved properties cost and depreciation, The amendment has no impact on reported profit or net book amounts of total proved properties.

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).
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 and pre development studies, 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.

Movements in estimated net proved reserves

Crude oil[a b]									million barrels 2024
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	129	–	713	–	3	5	729	11	1,590
Undeveloped	74	–	352	–	5	–	323	1	755
	203	–	1,065	–	7	6	1,052	12	2,345
Changes attributable to									
Revisions of previous estimates	(12)	–	54	–	2	5	77	1	128
Improved recovery	–	–	2	–	–	–	–	–	2
Purchases of reserves-in-place	1	–	–	–	–	1	–	–	2
Discoveries and extensions	–	–	143	–	–	–	–	–	143
Production	(25)	–	(138)	–	(2)	(7)	(109)	(3)	(284)
Sales of reserves-in-place	–	–	(1)	–	(3)	(4)	–	–	(7)
	(36)	–	61	–	(2)	(5)	(31)	(2)	(16)
At 31 December[c]									
Developed	104	–	653	–	1	1	716	9	1,483
Undeveloped	63	–	472	–	4	–	305	1	846
	167	–	1,125	–	5	1	1,021	10	2,329
Equity-accounted entities (bp share)[d]									
At 1 January									
Developed	–	89	–	11	275	99	115	–	588
Undeveloped	–	45	–	–	253	88	2	–	387
	–	133	–	11	528	187	117	–	976
Changes attributable to									
Revisions of previous estimates	–	4	–	–	(25)	10	19	–	8
Improved recovery	–	1	–	–	–	–	–	–	1
Purchases of reserves-in-place	–	–	–	–	–	5	–	–	5
Discoveries and extensions	–	–	–	–	18	–	–	–	18
Production	–	(21)	–	(1)	(20)	(30)	(25)	–	(97)
Sales of reserves-in-place	–	–	–	–	(14)	–	–	–	(15)
	–	(16)	–	(1)	(41)	(16)	(6)	–	(80)
At 31 December									
Developed	–	76	–	10	271	94	107	–	558
Undeveloped	–	42	–	–	217	77	3	–	339
	–	118	–	10	488	170	110	–	896
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	129	89	713	11	278	104	844	11	2,179
Undeveloped	74	45	352	–	258	88	324	1	1,142
	203	133	1,065	11	536	192	1,168	12	3,321
At 31 December									
Developed	104	76	653	10	271	95	823	9	2,041
Undeveloped	63	42	472	–	221	77	308	1	1,184
	167	118	1,125	10	493	171	1,131	10	3,225

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 1.5 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.

Movements in estimated net proved reserves – continued

									million barrels
Natural gas liquids[a b]									**2024**
	Europe		**North America**		**South America**	**Africa**	**Asia**	**Australasia**	**Total**
	UK	**Rest of Europe**	**US**[c]	**Rest of North America**					
Subsidiaries									
At 1 January									
Developed	3	–	180	–	–	–	–	1	184
Undeveloped	–	–	217	–	–	–	–	–	217
	3	–	397	–	–	–	–	1	401
Changes attributable to									
Revisions of previous estimates	–	–	89	–	2	–	–	1	93
Improved recovery	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	1	–	–	–	–	–	1
Discoveries and extensions	–	–	4	–	–	–	–	–	4
Production[c]	(1)	–	(39)	–	(2)	–	–	(1)	(43)
Sales of reserves-in-place	–	–	(4)	–	–	–	–	–	(4)
	(1)	–	51	–	–	–	–	–	51
At 31 December[d]									
Developed	2	–	202	–	1	–	–	1	206
Undeveloped	–	–	246	–	–	–	–	–	246
	3	–	447	–	1	–	–	1	452
Equity-accounted entities (bp share)[e]									
At 1 January									
Developed	–	3	–	–	3	14	–	–	19
Undeveloped	–	5	–	–	1	–	–	–	6
	–	8	–	–	4	14	–	–	25
Changes attributable to									
Revisions of previous estimates	–	1	–	–	–	(2)	–	–	(1)
Improved recovery	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	–	–	–
Production	–	(1)	–	–	–	(2)	–	–	(3)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	(4)	–	–	(4)
At 31 December									
Developed	–	3	–	–	3	10	–	–	16
Undeveloped	–	5	–	–	–	–	–	–	6
	–	8	–	–	4	10	–	–	22
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	3	3	180	–	3	14	–	1	204
Undeveloped	–	5	217	–	1	–	–	–	223
	3	8	397	–	4	14	–	1	427
At 31 December									
Developed	2	3	202	–	4	10	–	1	222
Undeveloped	–	5	246	–	–	–	–	–	252
	3	8	447	–	4	10	–	1	474

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 0.2 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.

Movements in estimated net proved reserves – continued

million barrels

Total liquids[a b]									2024
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America					
Subsidiaries									
At 1 January									
Developed	132	–	893	–	3	6	729	11	1,775
Undeveloped	75	–	568	–	5	–	323	1	971
	207	–	1,462	–	7	6	1,052	13	2,746
Changes attributable to									
Revisions of previous estimates	(11)	–	144	–	4	6	77	2	221
Improved recovery	–	–	2	–	–	–	–	–	2
Purchases of reserves-in-place	1	–	1	–	–	1	–	–	3
Discoveries and extensions	–	–	146	–	–	–	–	–	147
Production[c]	(27)	–	(177)	–	(3)	(7)	(109)	(4)	(326)
Sales of reserves-in-place	–	–	(5)	–	(3)	(4)	–	–	(11)
	(37)	–	111	–	(2)	(5)	(31)	(1)	35
At 31 December[d]									
Developed	106	–	855	–	1	1	716	10	1,689
Undeveloped	63	–	718	–	4	–	305	1	1,092
	169	–	1,573	–	6	1	1,021	11	2,781
Equity-accounted entities (bp share)[e]									
At 1 January									
Developed	–	92	–	11	278	113	115	–	608
Undeveloped	–	49	–	–	254	88	2	–	393
	–	141	–	11	532	200	117	–	1,001
Changes attributable to									
Revisions of previous estimates	–	5	–	–	(25)	8	19	–	8
Improved recovery	–	1	–	–	–	–	–	–	1
Purchases of reserves-in-place	–	–	–	–	–	5	–	–	5
Discoveries and extensions	–	–	–	–	18	–	–	–	18
Production	–	(22)	–	(1)	(20)	(32)	(25)	–	(100)
Sales of reserves-in-place	–	–	–	–	(14)	–	–	–	(15)
	–	(16)	–	(1)	(41)	(20)	(6)	–	(84)
At 31 December									
Developed	–	78	–	10	274	103	107	–	573
Undeveloped	–	47	–	–	217	77	3	–	344
	–	125	–	10	491	180	110	–	918
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	132	92	893	11	281	118	844	11	2,382
Undeveloped	75	49	568	–	259	88	324	1	1,365
	207	141	1,462	11	540	206	1,168	13	3,747
At 31 December									
Developed	106	78	855	10	275	105	823	10	2,263
Undeveloped	63	47	718	–	222	77	308	1	1,436
	169	125	1,573	10	497	182	1,131	11	3,699

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 1.7 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.

Movements in estimated net proved reserves – continued

Natural gas[a b]									billion cubic feet 2024
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	221	–	2,672	–	931	518	3,051	1,550	8,942
Undeveloped	34	–	3,229	–	503	207	1,672	358	6,003
	255	–	5,901	–	1,434	724	4,722	1,907	14,944
Changes attributable to									
Revisions of previous estimates	12	–	(241)	–	(174)	133	237	(40)	(73)
Improved recovery	–	–	1	–	–	–	–	–	1
Purchases of reserves-in-place	3	–	34	–	–	46	–	–	83
Discoveries and extensions	–	–	32	–	8	–	11	142	193
Production[c]	(80)	–	(639)	–	(423)	(340)	(625)	(325)	(2,432)
Sales of reserves-in-place	–	–	(76)	–	(115)	(402)	–	–	(594)
	(65)	–	(889)	–	(704)	(564)	(376)	(222)	(2,821)
At 31 December[d]									
Developed	162	–	2,600	–	379	161	3,026	1,254	7,582
Undeveloped	29	–	2,412	–	350	–	1,320	431	4,542
	190	–	5,012	–	730	161	4,346	1,685	12,124
Equity-accounted entities (bp share)[e]									
At 1 January									
Developed	–	67	–	4	1,027	463	46	–	1,608
Undeveloped	–	110	–	–	621	188	–	–	919
	–	177	–	4	1,648	651	46	–	2,527
Changes attributable to									
Revisions of previous estimates	–	1	–	–	(32)	(59)	–	–	(89)
Improved recovery	–	2	–	–	–	–	–	–	2
Purchases of reserves-in-place	–	–	–	–	–	205	–	–	205
Discoveries and extensions	–	–	–	–	221	–	–	–	221
Production[c]	–	(20)	–	–	(129)	(46)	(2)	–	(199)
Sales of reserves-in-place	–	–	–	–	(4)	–	–	–	(5)
	–	(18)	–	–	56	100	(2)	–	135
At 31 December									
Developed	–	49	–	4	1,053	536	43	–	1,686
Undeveloped	–	111	–	–	651	215	–	–	976
	–	160	–	4	1,704	751	43	–	2,662
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	221	67	2,672	4	1,958	981	3,096	1,550	10,549
Undeveloped	34	110	3,229	–	1,125	394	1,672	358	6,922
	255	177	5,901	4	3,082	1,375	4,768	1,907	17,471
At 31 December									
Developed	162	49	2,600	4	1,433	697	3,070	1,254	9,268
Undeveloped	29	111	2,412	–	1,001	215	1,320	431	5,518
	190	160	5,012	4	2,434	911	4,390	1,685	14,786

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 100 billion cubic feet of natural gas consumed in operations, 62 billion cubic feet in subsidiaries, 38 billion cubic feet in equity-accounted entities.
d Includes 219 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.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]	Europe		North America		South America	Africa	Asia	Australasia	Total
2024	UK	Rest of Europe	US[f]	Rest of North America					
Subsidiaries									
At 1 January									
Developed	170	–	1,354	–	163	95	1,255	279	3,316
Undeveloped	81	–	1,125	–	91	36	611	63	2,006
	251	–	2,479	–	255	131	1,866	341	5,323
Changes attributable to									
Revisions of previous estimates	(9)	–	102	–	(26)	28	118	(5)	208
Improved recovery	–	–	2	–	–	–	–	–	2
Purchases of reserves-in-place	1	–	7	–	–	9	–	–	17
Discoveries and extensions	–	–	152	–	1	–	2	25	180
Production[d e]	(41)	–	(287)	–	(76)	(66)	(216)	(60)	(746)
Sales of reserves-in-place	–	–	(18)	–	(22)	(73)	–	–	(113)
	(49)	–	(42)	–	(123)	(102)	(96)	(40)	(451)
At 31 December[f]									
Developed	134	–	1,303	–	67	29	1,237	226	2,997
Undeveloped	68	–	1,134	–	65	–	533	76	1,875
	202	–	2,437	–	131	29	1,770	302	4,871
Equity-accounted entities (bp share)[g]									
At 1 January									
Developed	–	103	–	12	455	192	123	–	885
Undeveloped	–	68	–	–	361	120	2	–	552
	–	172	–	12	816	313	124	–	1,437
Changes attributable to									
Revisions of previous estimates	–	5	–	–	(30)	(2)	19	–	(8)
Improved recovery	–	1	–	–	–	–	–	–	1
Purchases of reserves-in-place	–	–	–	–	–	40	–	–	40
Discoveries and extensions	–	–	–	–	56	–	–	–	56
Production[e]	–	(26)	–	(1)	(42)	(40)	(26)	–	(135)
Sales of reserves-in-place	–	–	–	–	(15)	–	–	–	(16)
	–	(19)	–	(1)	(31)	(3)	(7)	–	(60)
At 31 December									
Developed	–	87	–	11	456	196	115	–	864
Undeveloped	–	66	–	–	330	114	3	–	513
	–	153	–	11	785	310	118	–	1,377
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	170	103	1,354	12	618	287	1,378	279	4,201
Undeveloped	81	68	1,125	–	453	156	613	63	2,558
	251	172	2,479	12	1,071	444	1,991	341	6,759
At 31 December									
Developed	134	87	1,303	11	522	225	1,352	226	3,860
Undeveloped	68	66	1,134	–	394	114	535	76	2,387
	202	153	2,437	11	917	339	1,888	302	6,248

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 17 million barrels of oil equivalent of natural gas consumed in operations, 11 million barrels of oil equivalent in subsidiaries, 6 million barrels of oil equivalent in equity-accounted entities.
f Includes 39 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.

Movements in estimated net proved reserves – continued

									million barrels
Crude oil[a b]									2023
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
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
Changes attributable to									
Revisions of previous estimates	(32)	–	(60)	–	(1)	(3)	85	(6)	(15)
Improved recovery	–	–	14	–	–	–	–	–	14
Purchases of reserves-in-place	–	–	14	–	–	–	–	–	14
Discoveries and extensions	–	–	17	–	–	–	1	–	18
Production	(27)	–	(123)	–	(1)	(11)	(107)	(4)	(274)
Sales of reserves-in-place	–	–	(1)	–	–	(6)	–	–	(7)
	(58)	–	(141)	–	(2)	(20)	(21)	(9)	(252)
At 31 December[c]									
Developed	129	–	713	–	3	5	729	11	1,590
Undeveloped	74	–	352	–	5	–	323	1	755
	203	–	1,065	–	7	6	1,052	12	2,345
Equity-accounted entities (bp share)[d]									
At 1 January									
Developed	–	90	–	5	276	127	95	–	592
Undeveloped	–	16	–	7	244	74	1	–	342
	–	106	–	12	520	201	96	–	935
Changes attributable to									
Revisions of previous estimates	–	6	–	–	7	15	43	–	71
Improved recovery	–	21	–	–	4	–	–	–	24
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	22	–	–	19	–	–	–	41
Production	–	(22)	–	(1)	(20)	(30)	(23)	–	(95)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	27	–	(1)	9	(14)	20	–	41
At 31 December									
Developed	–	89	–	11	275	99	115	–	588
Undeveloped	–	45	–	–	253	88	2	–	387
	–	133	–	11	528	187	117	–	976
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
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
At 31 December									
Developed	129	89	713	11	278	104	844	11	2,179
Undeveloped	74	45	352	–	258	88	324	1	1,142
	203	133	1,065	11	536	192	1,168	12	3,321

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 2.2 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.

Movements in estimated net proved reserves – continued

Natural gas liquids[a b]									million barrels 2023
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America					
Subsidiaries									
At 1 January									
Developed	6	–	181	–	1	6	–	1	196
Undeveloped	–	–	236	–	–	1	–	–	237
	6	–	417	–	1	7	–	1	432
Changes attributable to									
Revisions of previous estimates	(1)	–	(14)	–	–	–	–	1	(14)
Improved recovery	–	–	15	–	–	–	–	–	16
Purchases of reserves-in-place	–	–	12	–	–	–	–	–	12
Discoveries and extensions	–	–	–	–	–	–	–	–	–
Production[c]	(2)	–	(31)	–	(1)	(1)	–	(1)	(35)
Sales of reserves-in-place	–	–	(3)	–	–	(6)	–	–	(9)
	(3)	–	(20)	–	(1)	(7)	–	–	(31)
At 31 December[d]									
Developed	3	–	180	–	–	–	–	1	184
Undeveloped	–	–	217	–	–	–	–	–	217
	3	–	397	–	–	–	–	1	401
Equity-accounted entities (bp share)[e]									
At 1 January									
Developed	–	4	–	–	3	17	–	–	23
Undeveloped	–	–	–	–	1	9	–	–	10
	–	4	–	–	4	26	–	–	34
Changes attributable to									
Revisions of previous estimates	–	–	–	–	1	(11)	–	–	(10)
Improved recovery	–	1	–	–	–	–	–	–	1
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	4	–	–	–	–	–	–	4
Production	–	(1)	–	–	–	(1)	–	–	(3)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	4	–	–	–	(12)	–	–	(8)
At 31 December									
Developed	–	3	–	–	3	14	–	–	19
Undeveloped	–	5	–	–	1	–	–	–	6
	–	8	–	–	4	14	–	–	25
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	6	4	181	–	4	23	–	1	219
Undeveloped	–	–	236	–	1	10	–	–	247
	6	4	417	–	5	33	–	1	466
At 31 December									
Developed	3	3	180	–	3	14	–	1	204
Undeveloped	–	5	217	–	1	–	–	–	223
	3	8	397	–	4	14	–	1	427

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 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.

Movements in estimated net proved reserves – continued

Total liquids[a b]									million barrels 2023
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America					
Subsidiaries									
At 1 January									
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
Changes attributable to									
Revisions of previous estimates	(33)	–	(74)	–	(1)	(3)	85	(5)	(30)
Improved recovery	–	–	29	–	–	–	–	–	29
Purchases of reserves-in-place	–	–	25	–	–	–	–	–	25
Discoveries and extensions	–	–	17	–	–	–	1	–	18
Production[c]	(29)	–	(154)	–	(3)	(12)	(107)	(4)	(309)
Sales of reserves-in-place	–	–	(4)	–	–	(12)	–	–	(17)
	(61)	–	(161)	–	(3)	(27)	(21)	(9)	(283)
At 31 December[d]									
Developed	132	–	893	–	3	6	729	11	1,775
Undeveloped	75	–	568	–	5	–	323	1	971
	207	–	1,462	–	7	6	1,052	13	2,746
Equity-accounted entities (bp share)[e]									
At 1 January									
Developed	–	94	–	5	278	144	95	–	616
Undeveloped	–	16	–	7	245	83	1	–	352
	–	110	–	12	523	227	96	–	968
Changes attributable to									
Revisions of previous estimates	–	6	–	–	7	4	43	–	61
Improved recovery	–	22	–	–	4	–	–	–	26
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	26	–	–	19	–	–	–	45
Production	–	(23)	–	(1)	(20)	(31)	(23)	–	(98)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	31	–	(1)	9	(27)	20	–	33
At 31 December									
Developed	–	92	–	11	278	113	115	–	608
Undeveloped	–	49	–	–	254	88	2	–	393
	–	141	–	11	532	200	117	–	1,001
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
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
At 31 December									
Developed	132	92	893	11	281	118	844	11	2,382
Undeveloped	75	49	568	–	259	88	324	1	1,365
	207	141	1,462	11	540	206	1,168	13	3,747

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 2.2 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.

Movements in estimated net proved reserves – continued

									billion cubic feet
Natural gas[a b]									2023
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
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
Changes attributable to									
Revisions of previous estimates	(54)	–	212	–	34	42	563	100	897
Improved recovery	9	–	254	–	–	–	–	–	263
Purchases of reserves-in-place	–	–	206	–	–	–	–	–	206
Discoveries and extensions	–	–	5	–	14	–	34	–	53
Production[c]	(100)	–	(560)	–	(439)	(462)	(594)	(284)	(2,439)
Sales of reserves-in-place	–	–	(25)	–	–	(97)	–	–	(123)
	(146)	–	92	–	(391)	(518)	3	(184)	(1,143)
At 31 December[d]									
Developed	221	–	2,672	–	931	518	3,051	1,550	8,942
Undeveloped	34	–	3,229	–	503	207	1,672	358	6,003
	255	–	5,901	–	1,434	724	4,722	1,907	14,944
Equity-accounted entities (bp share)[e]									
At 1 January									
Developed	–	72	–	3	974	534	43	–	1,627
Undeveloped	–	5	–	2	606	154	–	–	767
	–	77	–	5	1,580	689	43	–	2,394
Changes attributable to									
Revisions of previous estimates	–	12	–	–	8	4	5	–	29
Improved recovery	–	25	–	–	22	–	–	–	47
Purchases of reserves-in-place	–	–	–	–	132	–	–	–	132
Discoveries and extensions	–	85	–	–	118	–	–	–	203
Production[c]	–	(22)	–	–	(128)	(41)	(2)	–	(194)
Sales of reserves-in-place	–	–	–	–	(84)	–	–	–	(84)
	–	101	–	(1)	68	(38)	3	–	133
At 31 December									
Developed	–	67	–	4	1,027	463	46	–	1,608
Undeveloped	–	110	–	–	621	188	–	–	919
	–	177	–	4	1,648	651	46	–	2,527
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
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
At 31 December									
Developed	221	67	2,672	4	1,958	981	3,096	1,550	10,549
Undeveloped	34	110	3,229	–	1,125	394	1,672	358	6,922
	255	177	5,901	4	3,082	1,375	4,768	1,907	17,471

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 99 billion cubic feet of natural gas consumed in operations, 62 billion cubic feet in subsidiaries, 36 billion cubic feet in equity-accounted entities.
d Includes 430 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.

Movements in estimated net proved reserves – continued

Total hydrocarbons[a b]									million barrels of oil equivalent[c] 2023
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US[f]	Rest of North America					
Subsidiaries									
At 1 January									
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
Changes attributable to									
Revisions of previous estimates	(42)	–	(37)	–	5	5	182	12	125
Improved recovery	2	–	73	–	–	–	–	–	75
Purchases of reserves-in-place	–	–	61	–	–	–	–	–	61
Discoveries and extensions	–	–	18	–	2	–	7	–	27
Production[d e]	(46)	–	(251)	–	(78)	(92)	(210)	(53)	(730)
Sales of reserves-in-place	–	–	(9)	–	–	(29)	–	–	(38)
	(86)	–	(145)	–	(71)	(116)	(21)	(41)	(480)
At 31 December[f]									
Developed	170	–	1,354	–	163	95	1,255	279	3,316
Undeveloped	81	–	1,125	–	91	36	611	63	2,006
	251	–	2,479	–	255	131	1,866	341	5,323
Equity-accounted entities (bp share)[g]									
At 1 January									
Developed	–	106	–	6	446	236	102	–	896
Undeveloped	–	17	–	7	349	110	1	–	485
	–	123	–	13	796	346	103	–	1,381
Changes attributable to									
Revisions of previous estimates	–	8	–	–	9	5	44	–	66
Improved recovery	–	26	–	–	7	–	–	–	34
Purchases of reserves-in-place	–	–	–	–	–	23	–	–	23
Discoveries and extensions	–	41	–	–	39	–	–	–	80
Production[e]	–	(27)	–	(1)	(42)	(38)	(23)	–	(131)
Sales of reserves-in-place	–	–	–	–	(15)	–	–	–	(15)
	–	48	–	(1)	(2)	(11)	21	–	56
At 31 December									
Developed	–	103	–	12	455	192	123	–	885
Undeveloped	–	68	–	–	361	120	2	–	552
	–	172	–	12	816	313	124	–	1,437
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
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
At 31 December									
Developed	170	103	1,354	12	618	287	1,378	279	4,201
Undeveloped	81	68	1,125	–	453	156	613	63	2,558
	251	172	2,479	12	1,071	444	1,991	341	6,759

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 17 million barrels of oil equivalent of natural gas consumed in operations, 11 million barrels of oil equivalent in subsidiaries, 6 million barrels of oil equivalent in equity-accounted entities.
f Includes 39 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.

Movements in estimated net proved reserves – continued

Crude oil[a b]										million barrels 2022
	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[f]	–	(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
Natural gas liquids[a b]										2022
	Europe		North America		South America	Africa[c]	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	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[d]	(2)	–	(28)	–	(2)	(2)	–	–	(1)	(34)
Sales of reserves-in-place	–	–	(1)	–	–	(1)	–	–	–	(1)
	(2)	–	90	–	(19)	(2)	–	–	(1)	64
At 31 December[e]										
Developed	6	–	181	–	1	6	–	–	1	196
Undeveloped	–	–	236	–	–	1	–	–	–	237
	6	–	417	–	1	7	–	–	1	432
Equity-accounted entities (bp share)[f]										
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 Includes assets held for sale in Algeria.
d Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.
e Includes 0.4 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 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

Total liquids[a b]										million barrels 2022
	Europe		North America		South America	Africa[c]	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
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[d]	(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[e]										
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)[f]										
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	—	(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 Includes assets held for sale in Algeria.
d Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.
e Also includes 3 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 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

Natural gas[a b]	billion cubic feet 2022									
	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	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[d]	(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[e]										
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)[f]										
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[d]	–	(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 assets held for sale in Algeria.
d 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.
e Includes 547 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 bp's decision to exit its 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[d]	Asia		Australasia	Total
	UK	Rest of Europe	US[e]	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[f g]	(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[e]										
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)[h]										
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[g]	–	(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 Includes assets held for sale in Algeria.
e Includes 39 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
f Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.
g 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.
h Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
i bp's decision to exit its Russia business, including our shareholding in Rosneft, is treated as sales of reserves in place.

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
									2024
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
At 31 December									
Subsidiaries									
Future cash inflows[a]	15,100	–	99,300	–	3,700	600	107,300	15,200	241,200
Future production cost[b]	11,800	–	39,100	–	2,900	100	37,800	3,900	95,600
Future development cost[b]	1,000	–	15,300	–	500	100	11,200	2,100	30,200
Future taxation[c]	2,200	–	7,100	–	100	100	42,800	2,400	54,700
Future net cash flows	100	–	37,800	–	200	300	15,500	6,800	60,700
10% annual discount[d]	100	–	15,400	–	(300)	–	4,900	2,200	22,300
Standardized measure of discounted future net cash flows[e]	–	–	22,400	–	500	300	10,600	4,600	38,400
Equity-accounted entities (bp share)[f]									
Future cash inflows[a]	–	11,700	–	–	41,600	15,100	8,400	–	76,800
Future production cost[b]	–	4,100	–	–	20,900	5,400	4,200	–	34,600
Future development cost[b]	–	2,000	–	–	4,100	2,200	2,900	–	11,200
Future taxation[c]	–	4,300	–	–	4,600	2,200	400	–	11,500
Future net cash flows	–	1,300	–	–	12,000	5,300	900	–	19,500
10% annual discount[d]	–	300	–	–	7,000	1,400	200	–	8,900
Standardized measure of discounted future net cash flows	–	1,000	–	–	5,000	3,900	700	–	10,600
Total subsidiaries and equity-accounted entities									
Standardized measure of discounted future net cash flows	–	1,000	22,400	–	5,500	4,200	11,300	4,600	49,000

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	(25,700)	(5,300)	(31,000)
Development costs for the current year as estimated in previous year	5,100	2,900	8,000
Extensions, discoveries and improved recovery, less related costs	400	300	700
Net changes in prices and production cost	(7,300)	(1,800)	(9,100)
Revisions of previous reserves estimates	2,500	300	2,800
Net change in taxation	11,200	2,100	13,300
Future development costs	(1,400)	(600)	(2,000)
Net change in purchase and sales of reserves-in-place	(1,400)	800	(600)
Addition of 10% annual discount	5,000	1,100	6,100
Total change in the standardized measure during the year[g]	(11,600)	(200)	(11,800)

a The marker prices used were Brent $81.17/bbl, Henry Hub $2.07/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 $164 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 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
									2023
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
At 31 December									
Subsidiaries									
Future cash inflows[a]	19,400	—	100,200	—	6,800	4,400	118,300	18,000	267,100
Future production cost[b]	11,900	—	37,500	—	4,300	600	39,600	4,500	98,400
Future development cost[b]	1,200	—	12,100	—	1,000	500	8,500	1,400	24,700
Future taxation[c]	4,100	—	8,400	—	500	1,100	49,900	3,800	67,800
Future net cash flows	2,200	—	42,200	—	1,000	2,200	20,300	8,300	76,200
10% annual discount[d]	900	—	16,300	—	(300)	400	6,300	2,600	26,200
Standardized measure of discounted future net cash flows[e]	1,300	—	25,900	—	1,300	1,800	14,000	5,700	50,000
Equity-accounted entities (bp share)[f]									
Future cash inflows[a]	—	13,700	—	—	44,600	15,200	9,000	—	82,500
Future production cost[b]	—	3,700	—	—	20,700	5,500	4,700	—	34,600
Future development cost[b]	—	2,100	—	—	5,200	2,300	3,100	—	12,700
Future taxation[c]	—	6,000	—	—	5,900	2,100	400	—	14,400
Future net cash flows	—	1,900	—	—	12,800	5,300	800	—	20,800
10% annual discount[d]	—	500	—	—	7,600	1,700	200	—	10,000
Standardized measure of discounted future net cash flows	—	1,400	—	—	5,200	3,600	600	—	10,800
Total subsidiaries and equity-accounted entities									
Standardized measure of discounted future net cash flows	1,300	1,400	25,900	—	6,500	5,400	14,600	5,700	60,800

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	(36,500)	(6,500)	(43,000)
Development costs for the current year as estimated in previous year	6,000	2,200	8,200
Extensions, discoveries and improved recovery, less related costs	500	800	1,300
Net changes in prices and production cost	(50,800)	(7,100)	(57,900)
Revisions of previous reserves estimates	2,500	1,300	3,800
Net change in taxation	30,000	5,100	35,100
Future development costs	(1,000)	(300)	(1,300)
Net change in purchase and sales of reserves-in-place	(800)	—	(800)
Addition of 10% annual discount	9,100	1,400	10,500
Total change in the standardized measure during the year[g]	(41,000)	(3,100)	(44,100)

a The marker prices used were Brent $83.27/bbl, Henry Hub $2.58/mmBtu.
b Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
c Taxation is computed with reference to appropriate year-end statutory corporate income tax rates.
d Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
e Non-controlling interests in BP Trinidad and Tobago LLC amounted to $392 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 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
										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 year[i]	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.
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.

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 2024, 2023 and 2022.

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
2024	**70**	**—**	**376**	**—**	**4**	**19**	**—**	**297**	**9**	**775**
2023	74	—	335	—	4	29	—	293	10	745
2022	80	—	296	15	5	83	—	307	12	797
Natural gas liquids										thousand barrels per day
2024	**4**	**—**	**107**	**—**	**4**	**1**	**—**	**—**	**2**	**117**
2023	5	—	88	—	4	2	—	—	2	100
2022	5	—	76	—	4	6	—	—	2	93
Natural gas[f]										million cubic feet per day
2024	**197**	**—**	**1,690**	**—**	**1,145**	**904**	**—**	**1,655**	**882**	**6,474**
2023	247	—	1,486	—	1,191	1,236	—	1,578	774	6,512
2022	271	—	1,291	—	1,276	1,353	—	1,485	752	6,428
Equity-accounted entities (bp share)										
Crude oil[e]										thousand barrels per day
2024	**—**	**58**	**—**	**—**	**56**	**82**	**—**	**69**	**—**	**266**
2023	—	60	—	—	57	82	—	62	—	261
2022	—	47	—	—	59	33	150	25	—	314
Natural gas liquids										thousand barrels per day
2024	**—**	**2**	**—**	**—**	**1**	**6**	**—**	**—**	**—**	**9**
2023	—	3	—	—	1	6	—	—	—	9
2022	—	2	—	—	1	5	—	—	—	9
Natural gas[f]										million cubic feet per day
2024	**—**	**55**	**—**	**—**	**300**	**85**	**—**	**—**	**—**	**440**
2023	—	58	—	—	299	74	—	—	—	432
2022	—	66	—	—	296	64	248	—	—	674

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 2024. 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[e]	Australasia[e]	Total[a]
		UK	Rest of Europe	US	Rest of North America					
Number of productive wells at 31 December 2024										
Oil wells[b]	– gross	**115**	**126**	**1,439**	**8**	**4,823**	**825**	**2,848**	**–**	**10,184**
	– net	**67**	**20**	**751**	**2**	**2,368**	**77**	**625**	**–**	**3,911**
Gas wells[c]	– gross	**36**	**10**	**3,607**	**–**	**1,209**	**89**	**185**	**89**	**5,225**
	– net	**8**	**2**	**1,819**	**–**	**392**	**37**	**70**	**21**	**2,348**
Oil and natural gas acreage at 31 December 2024										thousands of acres
Developed	– gross	**70**	**87**	**1,565**	**8**	**1,319**	**618**	**1,343**	**838**	**5,847**
	– net	**40**	**14**	**977**	**2**	**375**	**122**	**281**	**157**	**1,967**
Undeveloped[d]	– gross	**479**	**1,794**	**3,916**	**9,663**	**10,976**	**20,256**	**9,877**	**4,858**	**61,818**
	– net	**368**	**285**	**3,376**	**6,298**	**5,223**	**8,276**	**5,585**	**2,826**	**32,236**

a Because of rounding, some totals may not exactly agree with the sum of their component parts.
b Includes approximately 164 gross (29 net) multiple completion wells (more than one formation producing into the same well bore).
c Includes approximately 12 gross (5 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.
e Includes correction of acreage distribution between continents.

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		
2024										
Exploratory										
Productive	**–**	**–**	**0.7**	**–**	**0.5**	**0.4**	**–**	**0.7**	**–**	**2.3**
Dry	**–**	**–**	**1.0**	**0.8**	**0.5**	**–**	**–**	**0.5**	**–**	**2.8**
Development										
Productive	**1.5**	**0.5**	**149.0**	**–**	**69.3**	**2.5**	**–**	**55.1**	**–**	**277.8**
Dry	**–**	**–**	**15.0**	**–**	**–**	**1.1**	**–**	**0.5**	**–**	**16.6**
2023										
Exploratory										
Productive	–	–	2.0	–	–	–	–	0.8	0.4	3.2
Dry	0.5	–	0.8	0.5	–	–	–	0.2	–	2.0
Development										
Productive[b]	2.6	0.6	141.9	0.1	85.2	4.2	–	39.7	0.4	274.7
Dry	–	–	–	–	–	–	–	0.4	–	0.4
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

a Because of rounding, some totals may not exactly agree with the sum of their component parts.
b Includes correction of 2023 productive wells

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 2024. 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					
At 31 December 2024									
Exploratory									
Gross	–	–	2.0	–	3.0	2.0	4.0	–	11.0
Net	–	–	0.9	–	1.9	0.6	1.0	–	4.4
Development									
Gross	7.0	2.1	56.0	–	29.0	9.0	90.0	–	193.1
Net	3.7	0.3	36.4	–	10.9	4.4	20.5	–	76.1

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	Note	2024	$ million 2023
Dividend income		**15,654**	18,133
Interest and other income		**7,100**	6,007
Total income		**22,754**	24,140
Administrative and other expenses		**(764)**	(747)
Net impairment of fixed asset investments	2	**(539)**	—
Loss on termination of operations		**(28)**	(8)
Profit before interest and taxation		**21,423**	23,385
Interest payable to subsidiaries		**(10,594)**	(9,280)
Net finance income (expense) relating to pensions	4	**310**	391
Profit (loss) before taxation		**11,139**	14,496
Taxation	6	**(70)**	(126)
Profit (loss) for the year		**11,069**	14,370

Company statement of comprehensive income

For the year ended 31 December	Note	2024	$ million 2023
Profit for the year		**11,069**	14,370
Other comprehensive income			
Items that may be reclassified subsequently to profit or loss			
Currency translation differences		**(122)**	407
		(122)	407
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension liability or asset	4	**(684)**	(1,877)
Income tax relating to items that will not be reclassified	6	**866**	513
		182	(1,364)
Other comprehensive income		**60**	(957)
Total comprehensive income		**11,129**	13,413

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

Company balance sheet

At 31 December	Note	2024	$ million 2023
Non-current assets			
Investments	2	**177,349**	177,741
Receivables	3	**850**	853
Defined benefit pension plan surpluses	4	**6,083**	6,631
		184,282	185,225
Current assets			
Receivables	3	**6,185**	5,864
Cash and cash equivalents		**143**	208
		6,328	6,072
Total assets		**190,610**	191,297
Current liabilities			
Payables	5	**11,949**	11,707
Net current liabilities		**(5,621)**	(5,635)
Total assets less current liabilities		**178,661**	179,590
Non-current liabilities			
Payables	5	**53,488**	53,583
Deferred tax liabilities	6	**1,509**	2,305
Defined benefit pension plan deficits	4	**122**	143
		55,119	56,031
Total liabilities		**67,068**	67,738
Net assets		**123,542**	123,559
Capital and reserves[a]			
Profit and loss account			
Brought forward		**88,193**	88,541
Profit (loss) for the year		**11,069**	14,370
Other movements		**(13,473)**	(14,718)
		85,789	88,193
Called-up share capital	7	**4,186**	4,496
Share premium account		**14,031**	13,815
Other capital and reserves		**19,536**	17,055
		123,542	123,559

a See Statement of changes in equity on page 253 for further information.

The financial statements on pages 251-310 were approved and signed by the chief executive officer on 6 March 2025 having been duly authorized to do so by the board of directors:

Murray Auchincloss Chief executive officer

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

Company statement of changes in equity[a]

$ million

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Treasury shares	Foreign currency translation reserve	Profit and loss account	Total equity
At 1 January 2024	**4,496**	**13,815**	**2,496**	**26,509**	**(11,323)**	**(627)**	**88,193**	**123,559**
Profit for the year	**—**	**—**	**—**	**—**	**—**	**—**	**11,069**	**11,069**
Other comprehensive income	**—**	**—**	**—**	**—**	**—**	**(122)**	**182**	**60**
Total comprehensive income	**—**	**—**	**—**	**—**	**—**	**(122)**	**11,251**	**11,129**
Dividends	**—**	**—**	**—**	**—**	**—**	**—**	**(5,018)**	**(5,018)**
Repurchases of ordinary share capital[a]	**(310)**	**—**	**310**	**—**	**—**	**—**	**(7,302)**	**(7,302)**
Share-based payments, net of tax	**—**	**216**	**—**	**—**	**2,293**	**—**	**(1,335)**	**1,174**
At 31 December 2024	**4,186**	**14,031**	**2,806**	**26,509**	**(9,030)**	**(749)**	**85,789**	**123,542**
At 1 January 2023	4,795	13,692	2,180	26,509	(12,154)	(1,034)	88,541	122,529
Profit for the year	—	—	—	—	—	—	14,370	14,370
Other comprehensive income	—	—	—	—	—	407	(1,364)	(957)
Total comprehensive income	—	—	—	—	—	407	13,006	13,413
Dividends	—	—	—	—	—	—	(4,830)	(4,830)
Repurchases of ordinary share capital	(316)	—	316	—	—	—	(8,167)	(8,167)
Share-based payments, net of tax	17	123	—	—	831	—	(357)	614
At 31 December 2023	4,496	13,815	2,496	26,509	(11,323)	(627)	88,193	123,559

a See Note 7 for further information.

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

Notes on financial statements

1. Material accounting policy information, significant 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 2024 were approved and signed by the chief executive officer on 6 March 2025 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 of IAS 7 'Statement of Cash Flows' (excluding paragraphs 1 to 44E, 44H(b)(ii) and 45 to 63 which are not applicable';

(c) 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;

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

(e) 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;

(f) 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;

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

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

(i) the requirement of the second sentence of paragraph 110 and paragraphs 113(a), 114,115, 118, 119(a) to (c), 120 to 127 and 129 of IFRS 15 'Revenue from Contracts with Customers'.

Where required, equivalent disclosures are given in the consolidated financial statements of BP p.l.c.

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

There are no new IFRS Accounting Standards or amended standards or interpretations adopted from 1 January 2024 onwards that have a significant impact on the financial statements.

IFRS 18 'Presentation and Disclosure in Financial Statements' will supersede IAS 1 'Presentation of Financial Statements' and is effective for annual periods beginning on or after 1 January 2027 subject to endorsement by the UK Endorsement Board. IFRS 18 (and consequential amendments made to IAS 7 'Statement of Cash Flows', IAS 8 'Accounting Policies: Changes in Accounting Estimates and Errors', IAS 33 'Earnings per share' and IFRS 7 'Financial Instruments: Disclosures') introduces several new requirements that are expected to impact the presentation and disclosure of the Company's financial statements. These new requirements include:

- Requirements to classify all income and expenses included in the statement of profit or loss into one of five categories and to present two new mandatory subtotals.
- Required disclosures about certain non-GAAP measures ('management defined performance measures') in a single note to the financial statements.
- Enhanced guidance on the aggregation of information across all the primary financial statements and the notes.

The Company's evaluation of the effect of adopting IFRS 18 is ongoing.

Material accounting policy information: 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 Company 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.

1. Material accounting policy information, significant 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 were revised during 2024. The revised price assumptions have been rebased in real 2023 terms and are materially consistent with the disclosed prices in real 2022 terms. The near term Brent oil assumption was held constant at $70 per barrel to reflect near-term supply constraints before declining after 2030 to $50 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 2050 were held constant at $4.00 per mmBtu reflecting an assumption that declining domestic demand in the US is offset by higher LNG exports. The revised assumptions for Brent oil and Henry Hub gas 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 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.

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 115 to 222) 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 2024 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 Note 4 for further information.

Investments

Investments in subsidiaries are recorded at cost. The Company assesses investments for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If any such indication of impairment exists, the Company makes an estimate of its recoverable amount. Where the carrying amount of an investment exceeds its recoverable amount, the investment is considered impaired and is written down to its recoverable amount. Where these circumstances have reversed, the impairment previously made is reversed to the extent of the original cost of the investment.

Significant judgements and estimates: recoverability of asset carrying values

Determination as to whether, and by how much, an investment holding company chain (defined as each direct subsidiary and its own investments), is impaired involves management estimates on highly uncertain matters such as the effects of inflation and deflation on operating expenses, discount rates, capital expenditure, carbon pricing (where applicable), production profiles, reserves and resources, and future commodity prices, including the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas and refined products. Determination as to whether, and by how much, an asset or CGU is impaired involves similar estimates.

The recoverable amount of an asset is the higher of its value in use and its fair value less costs of disposal. Fair value less costs of disposal may be determined based on expected sales proceeds or similar recent market transaction data. Details of impairment charges recognized in the profit and loss account and the carrying amounts of investments are shown in Note 2. The estimates for assumptions made in impairment tests in 2024 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.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Discount rates

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the CGU. Value-in-use calculations are typically discounted using a pre-tax discount rate based upon the cost of funding the Company 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 2024, the post-tax discount rate was 8% (2023 8%) other than for renewable power assets. Where the CGU is located in a country that was judged to be higher risk, an additional premium of 1% to 3% was reflected in the post-tax discount rate (2023 1% to 4%). The judgement of classifying a country as higher risk and the applicable premium takes into account various economic and geopolitical factors. The pre-tax discount rate, other than for renewable power assets, typically ranged from 9% to 20% (2023 9% to 20%) depending on the risk premium and applicable tax rate in the geographic location of the CGU. For renewable power assets, which were tested primarily on a fair-value basis in 2024 (including those in equity accounted entities) tests were performed using a post-tax cost of equity-based discount rate range of 8.75% to 9.5%. In 2023, tests were performed on a value-in-use basis using a post-tax WACC-based discount rate of 6.5%.

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 145. 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 were revised. The revised price assumptions have been rebased in real 2023 terms and are materially consistent with the disclosed prices in real 2022 terms. The near term Brent oil assumption was held constant at $70 per barrel to reflect near term supply constraints before declining after 2030 to $50 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 2050 were held constant at $4.00 per mmBtu reflecting an assumption that declining domestic demand in the US is offset by higher LNG exports. These price assumptions are derived from the central case investment appraisal assumptions (see page 20). A summary of the group's revised price assumptions for Brent oil and Henry Hub gas, applied in 2024 and 2023, in real 2023 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. Inflation rate of 2% - 2.5% (2023 2%) is applied to determine the price assumptions in nominal terms.

2024 price assumptions	**2025**	**2030**	**2040**	**2050**
Brent oil ($/bbl)	70	70	63	50
Henry Hub gas ($/mmBtu)	4.00	4.00	4.00	4.00

2023 price assumptions	**2024**	**2025**	**2030**	**2040**	**2050**
Brent oil ($/bbl)	71	71	71	59	46
Henry Hub gas ($/mmBtu)	4.06	4.05	4.05	4.05	4.05

Oil and natural gas reserves

In addition to oil and natural gas prices, significant technical and commercial assessments are required to determine the Company'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 Company'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.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

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 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. Non-monetary items, 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 and 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. 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.

Pensions and other post-employment benefits

The defined benefit pension plans are plans that share risks between entities under common control. In each instance BP p.l.c. is the principal employer and carries the whole plan surplus or deficit on its balance sheet. The cost of providing benefits under the Company's defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period to determine current service cost and to the current and prior periods to determine the present value of the defined benefit obligation. Past service costs, resulting from either a plan amendment or a curtailment (a reduction in future obligations as a result of a material reduction in the plan membership), are recognized immediately when the company becomes committed to a change.

Net interest expense relating to pensions and other post-employment 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-employment benefits

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.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Deferred tax assets are only recognized to the extent that it is probable that they will be realized in the future.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date. Deferred tax assets and liabilities are not discounted. See Note 6 for further details.

In July 2023, the UK government enacted legislation to implement the Pillar Two Model rules. The legislation is effective for bp from 1 January 2024 and includes an income inclusion rule and a domestic minimum tax, which together are designed to ensure a minimum effective tax rate of 15% in each country in which bp operates. Similar legislation is being enacted by other governments around the world. In line with the amendments to IAS 12, the exception from recognising and disclosing information about deferred tax assets and liabilities related to Pillar Two income taxes has been applied.

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 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 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.

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 receivables.

Cash equivalents

Cash equivalents are held for the purpose of meeting short-term cash commitments and 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.

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 amounts payable to subsidiaries. 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.

2. Investments

			$ million
	Subsidiaries	Associates	
	Shares	Shares	Total
Cost			
At 1 January 2024	**181,406**	**9**	**181,415**
Additions	**203**	**–**	**203**
Disposals	**(61)**	**–**	**(61)**
At 31 December 2024	**181,548**	**9**	**181,557**
Amounts provided			
At 1 January 2024	**3,674**	**–**	**3,674**
Additions	**539**	**–**	**539**
Reversals	**(5)**	**–**	**(5)**
At 31 December 2024	**4,208**	**–**	**4,208**
Cost			
At 1 January 2023	169,148	9	169,157
Additions	12,266	–	12,266
Disposals	(8)	–	(8)
At 31 December 2023	181,406	9	181,415
Amounts provided			
At 1 January 2023	3,674	–	3,674
At 31 December 2023	3,674	–	3,674
At 31 December 2024	**177,340**	**9**	**177,349**
At 31 December 2023	177,732	9	177,741

At 31 December 2024, the carrying amount of the company's net assets of $123.5 billion (2023 $123.6 billion) exceeded the group's market capitalisation of $79.6 billion (2023 $102.2 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. Management considered the performance of investments and impairment tests performed by the company's subsidiaries. Taking into account the decrease in the group's market capitalisation and an increase in the deficits between the carrying amount of the company's major investments compared with the underlying net assets, compared to 2023, management concluded that an impairment was required, relating to deterioration of value in use and fair value less cost to sell. An impairment charge of $539 million were recognised against BP Global Investments Limited. Notwithstanding that there have been certain impairment reversals within some of the groups operating subsidiaries during the year, no reversals of previously recognised impairment provisions were determined to be required in respect of the company's investments in subsidiaries.

The more important subsidiaries of the company at 31 December 2024 and the percentage holding of ordinary share capital (to the nearest whole number) are set out below. For a full list of related undertakings see Note 14.

Subsidiaries	%	Country of incorporation	Principal activities
International			
BP Global Investments Limited	100	England & Wales	Investment holding
BP International Limited	100	England & Wales	Integrated oil operations
Castrol Group Holdings Limited	100	Scotland	Investment holding
BP Gamma Holdings Limited	100	England & Wales	Investment holding
Canada			
BP Holdings Canada Limited	100	England & Wales	Investment holding
US			
BP Holdings North America Limited	100	England & Wales	Investment holding

3. Receivables

				$ million
		2024		2023
	Current	Non-current	Current	Non-current
Amounts receivable from subsidiaries	**6,184**	**850**	5,862	853
Amounts receivable from associates	**1**	**–**	2	–
	6,185	**850**	5,864	853

The company has current receivables of $5,988 million on Internal Funding Accounts (IFAs) receivable from BP International Limited (2023 $4,161 million). 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.

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

4. Pensions

The defined benefit pension obligation consists primarily of a closed 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. Employees in the UK are eligible for membership of defined contribution plans established with third-party providers.

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 defined benefit 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 2026 formal actuarial valuation. No contractually committed funding was due at 31 December 2024.

The surplus relating to the primary UK defined benefit 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 2024. The primary UK defined benefit plan is subject to a formal actuarial valuation every 3 years. The most recent formal actuarial valuation of the primary UK defined benefit plan was as at 31 December 2023.

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		%
	2024	2023
Discount rate for plan liabilities	**5.5**	4.8
Rate of increase for pensions in payment	**2.9**	2.8
Rate of increase in deferred pensions	**2.9**	2.8
Inflation for plan liabilities	**3.1**	3.0

Financial assumptions used to determine benefit expense		%
	2024	2023
Discount rate for plan other finance expense	**4.8**	5.0

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:

Mortality assumptions		Years
	2024	2023
Life expectancy at age 60 for a male currently aged 60	**27.0**	27.4
Life expectancy at age 60 for a male currently aged 40	**28.9**	29.2
Life expectancy at age 60 for a female currently aged 60	**29.0**	29.2
Life expectancy at age 60 for a female currently aged 40	**30.5**	30.6

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

A proportion of the assets are held in equities, 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 defined benefit 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 defined benefit plan there is an agreement with the trustee to at least maintain the proportion of assets with liability matching characteristics and review over time. During 2024, the asset allocation policy remained unchanged.

4. Pensions – continued

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

Asset category	%
Total equity (including private equity)	**8**
Bonds/cash (including LDI)	**85**
Property/real estate	**7**

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2024 were $4,970 million (2023 $6,215 million) of government-issued nominal bonds and $11,105 million (2023 $13,177 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 262.

			$ million
		2024	2023
Fair value of pension plan assets			
Listed equities	– developed markets	**963**	862
	– emerging markets	**32**	28
Private equity[a]		**1,916**	2,022
Government issued nominal bonds[b]		**5,027**	6,285
Government issued index-linked bonds[b]		**11,105**	13,177
Corporate bonds[b]		**6,088**	6,144
Property[c]		**2,344**	2,437
Cash		**416**	453
Other		**1,039**	1,123
Debt (repurchase agreements) used to fund liability driven investments		**(5,664)**	(6,485)
		23,266	26,046

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.

		$ million
	2024	2023
Analysis of the amount charged to profit or loss		
Current service cost[a]	**48**	44
Past service cost[b]	**—**	4
Settlement	**(1)**	—
Operating charge / (credit) relating to defined benefit plans	**47**	48
Payments to defined contribution plan	**161**	132
Total operating charge / (credit)	**208**	180
Interest income on plan assets[c]	**(1,218)**	(1,259)
Interest on plan liabilities	**908**	868
Other finance (income)	**(310)**	(391)
Analysis of the amount recognized in other comprehensive income		
Actual asset return less interest income on pension plan assets	**(2,388)**	(677)
Change in financial assumptions underlying the present value of the plan liabilities	**1,498**	(650)
Change in demographic assumptions underlying the present value of plan liabilities	**194**	(229)
Experience gains and losses arising on the plan liabilities	**12**	(321)
Remeasurements recognized in other comprehensive income	**(684)**	(1,877)

a The costs of managing plan investments are offset against the investment return. Following the closure of the main UK pension plan current service cost consists of $38 million of the costs of administering the pension plan and $10 million of current service cost from the remaining small worldwide schemes administered and reported through the UK.
b Past service costs predominantly represent costs associated with the removal of some member benefits in non bp p.l.c pension plans being replaced with new arrangements and reported through bp p.l.c.
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

	2024	2023
		$ million
Movements in benefit obligation during the year		
Benefit obligation at 1 January	**19,558**	17,459
Exchange adjustments	**(352)**	1,055
Operating charge relating to defined benefit plans	**47**	48
Interest cost	**908**	868
Contributions by plan participants	**7**	6
Benefit payments (funded plans)[a]	**(1,153)**	(1,071)
Benefit payments (unfunded plans)[a]	**(6)**	(7)
Remeasurements	**(1,704)**	1,200
Benefit obligation at 31 December	**17,305**	19,558
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	**26,046**	25,047
Exchange adjustments	**(473)**	1,462
Interest income on plan assets[b]	**1,218**	1,259
Contributions by plan participants	**7**	6
Contributions by employers (funded plans)	**9**	20
Benefit payments (funded plans)[a]	**(1,153)**	(1,071)
Remeasurements[b]	**(2,388)**	(677)
Fair value of plan assets at 31 December[c d]	**23,266**	26,046
Surplus at 31 December	**5,961**	6,488
Represented by		
Asset recognized	**6,083**	6,631
Liability recognized	**(122)**	(143)
	5,961	6,488
The surplus may be analysed between funded and unfunded plans as follows		
Funded	**6,083**	6,631
Unfunded	**(122)**	(143)
	5,961	6,488
The defined benefit obligation may be analysed between funded and unfunded plans as follows		
Funded	**(17,183)**	(19,415)
Unfunded	**(122)**	(143)
	(17,305)	(19,558)

a The benefit payments amount shown above comprises $1,121 million benefits (2023 $1,044 million) plus $38 million (2023 $34 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 $22,964 million of assets held in the BP Pension Fund (2023 $25,760 million) and $260 million held in the BP Global Pension Trust (2023 $241 million), as well as $33 million representing the company's share of Merchant Navy Officers Pension Fund (2023 $35 million) and $9 million of Merchant Navy Ratings Pension Fund (2023 $10 million).
d The fair value of plan assets includes borrowings related to the LDI programme as described on page 261.

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 2024 for the company's plans would have had the effects shown in the table below. The effects shown for the expense in 2025 comprise the total of current service cost and net finance income or expense.

	One percentage point Increase	One percentage point Decrease
		$ million
Discount rate[a]		
Effect on pension expense in 2025	**(180)**	**162**
Effect on pension obligation at 31 December 2024	**(1,816)**	**2,217**
Inflation rate[b]		
Effect on pension expense in 2025	**81**	**(77)**
Effect on pension obligation at 31 December 2024	**1,460**	**(1,390)**

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 2025 pension expense by $32 million and the pension obligation at 31 December 2024 by $580 million.

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

4. Pensions – continued

Estimated future benefit payments and the weighted average duration of defined benefit obligations

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, and the weighted average duration of the defined benefit obligations at 31 December 2024 are as follows:

	$ million
Estimated future benefit payments	
2025	**1,080**
2026	**1,105**
2027	**1,125**
2028	**1,138**
2029	**1,158**
2030 - 2034	**5,883**
	Years
Weighted average duration	**11.7**

5. Payables

				$ million
		2024		2023
	Current	**Non-current**	Current	Non-current
Amounts payable to subsidiaries	**10,807**	**53,436**	10,750	53,439
Accruals	**934**	**—**	747	11
Other payables	**208**	**52**	210	133
	11,949	**53,488**	11,707	53,583

Included in current amounts payable to subsidiaries are interest-bearing payables with BP Finance p.l.c. and BP Gamma Holdings Limited. The interest-bearing payable of $5,072 million (2023 $5,079 million) with BP Finance p.l.c. has interest charged based on a 3-month Term SOFR rate plus 0.12% with a maturity date of April 2030. Though the loan with BP Finance p.l.c. is due in 2030, the loan is repayable 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 interest-bearing payable of $5,500 million (2023 $5,500 million) with BP Gamma Holdings Limited has interest charged based on a SOFR plus 23 basis points with a maturity date of December 2025 and repayable at two business day's notice. Though the loan with BP Gamma Holdings Limited is due in 2025, the loan is auto-renewal. It is disclosed as a non-current receivable in the financial statements of BP Gamma Holdings Limited, given the counterparty has no intent to withdraw the loan within the next year.

Non-current amounts payable to subsidiaries includes an interest-bearing payable of $52,585 million with BP International Limited issued in December 2021 (2023 $52,585 million), with interest being charged based on a 3-month USD synthetic LIBOR rate plus 75 basis points and a maturity date of December 2028. With effect from 23 December 2024, interest will be charged based on a 3-month Term SOFR rate plus 101 basis points. 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.

		$ million
	2024	2023
Due within		
1 to 2 years	**62**	129
2 to 5 years	**52,752**	52,747
More than 5 years	**674**	707
	53,488	53,583

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp’s Annual Report on Form 20-F as filed with the SEC.

6. Taxation

		$ million
Tax charge included in total comprehensive income	**2024**	2023
Deferred tax		
Origination and reversal of temporary differences in the current year	**(798)**	(387)
This comprises:		
Taxable temporary differences relating to pensions	**(798)**	(387)
Deferred tax		
Deferred tax liability		
Pensions[a]	**1,509**	2,305
Net deferred tax liability	**1,509**	2,305
Analysis of movements during the year		
At 1 January	**2,305**	2,692
Charge (credit) for the year in the income statement	**70**	126
Charge (credit) for the year in other comprehensive income[a]	**(866)**	(513)
At 31 December	**1,509**	2,305

a 2024 reflects a $658 million reduction in the deferred tax liability on defined benefit pension plan surpluses following the reduction in the rate of the authorized surplus payments tax charge in the UK from 35% to 25%.

At 31 December 2024, deferred tax assets of $913 million on other temporary differences; $27 million relating to pensions, $206 million relating to income losses and $680 million relating to other deductible temporary differences (2023 $817 million on other temporary differences, $32 million relating to pensions; $159 million relating to income losses and $626 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:

	2024		2023	
Issued	**Shares thousand**	**$ million**	Shares thousand	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9
		21		21
Ordinary shares of 25 cents each				
At 1 January	**17,900,800**	**4,475**	19,097,783	4,774
Issue of new shares for employee share-based payment plans	**—**	**—**	66,000	17
Repurchase of ordinary share capital	**(1,238,335)**	**(310)**	(1,262,983)	(316)
At 31 December	**16,662,465**	**4,165**	17,900,800	4,475
		4,186		4,496

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 2024 the company repurchased 1,238 million ordinary shares for a total consideration of $7,127 million, including transaction costs of $38 million. All shares purchased were for cancellation. The repurchased shares represented 7.4% of ordinary share capital. A further 176 million ordinary shares were repurchased between the end of the reporting period and 14 February 2025, the latest practicable date before the completion of these financial statements, for a total cost of $927 million of which $922 million has been accrued at 31 December 2024. The number of shares in issue is reduced when shares are repurchased.

7. Called-up share capital – continued

Treasury shares[a]

	2024		2023	
	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,077,079**	**271**	1,124,927	281
Purchases for settlement of employee share plans	**8,302**	**2**	24,688	6
Issue of new shares for employee share-based payment plans	**—**	**—**	71,039	19
Shares re-issued for employee share-based payment plans	**(273,360)**	**(69)**	(143,575)	(35)
At 31 December	**812,021**	**204**	1,077,079	271
Of which - shares held in treasury by bp	**481,474**	**121**	726,339	183
- shares held in ESOP trusts	**330,510**	**83**	350,704	88
- shares held by bp's US plan administrator[b]	**37**	**—**	36	—

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 4.1% (2023 4.9%) of the called-up ordinary share capital of the company.

During 2024, the movement in shares held in treasury by bp represented 1.4% (2023 1.1%) 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 premium arising where the fair value of the consideration given is in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares where merger relief under the Companies Act applies..

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 $23,932 million (2023 $23,858 million), the distribution of which is limited by statutory or other restrictions.

The financial statements for the year ended 31 December 2024 do not reflect the dividend announced on 11 February 2025 and which is expected to be paid on 28 March 2025; this will be treated as an appropriation of profit in the year ending 31 December 2025.

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 2024, for these arrangements is $412 million (2023 $649 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 2024, maximum guaranteed amounts pertaining to debt and lease arrangements were $69,054 million (2023 $61,900 million). These maximum amounts are more than the actual guaranteed exposure of due at the balance sheet date as well as more than remaining obligations under the guaranteed contracts. The recognised liability due to provided financial guarantees was $854 million at the balance sheet date (2023 $865 million). The liability was included within Payables.

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.

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

9. Financial guarantees and other contingencies – continued

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 America oil spill. The company has also issued uncapped guarantees for certain subsidiaries' liabilities under the Plaintiffs' Steering Committee agreement relating to the Gulf of America 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.

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.

Subsidiary audit exemptions

The following UK subsidiaries will take advantage of the audit exemption set out within Section 479A of the Companies Act 2006 supported by guarantees issued by BP p.l.c. over their liabilities as at 31 December 2024.

Name	Company number
Atlantic 2/3 UK Holdings Limited	04075308
BP Africa Oil Limited	11807924
BP Australia Swaps Management Limited	8298838
BP Car Fleet Limited	00651878
BP East Kalimantan CBM Limited	06383221
BP Energy Europe Limited	SC107896
BP Eta Holdings Limited	14846392
BP Exploration Orinoco Limited	00598148
BP Global Solutions Limited	13464292
BP Holdings Canada Limited	08274009
BP Integrated Solutions Limited	13448827
BP Investments Asia Limited	05639411
BP Oil Vietnam Limited	00567280
BP Retail Properties Limited	12735096
Kenilworth Oil Company Limited	00273831
Viceroy Investments Limited	00432981

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
Remuneration of directors	2024	2023
Total for all directors		
Emoluments	8	8
Amounts awarded under incentive schemes[a]	5	6
Total	13	14

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 88.

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

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

12. Employee costs and numbers

		$ million
Employee costs	2024	2023
Wages and salaries	**1,168**	1,211
Social security costs	**202**	192
	1,370	1,403

Average number of employees	2024	2023
gas & low carbon energy	**520**	430
oil production & operations	**192**	168
customers & products	**1,650**	1,571
other businesses and corporate	**2,235**	2,076
	4,597	4,245

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

13. Events after the reporting period

On 26 February 2025, bp announced a fundamentally reset strategy, with significant capital reallocation, and plans to drive improved performance, aimed at growing free cash flow, returns and long-term shareholder value. This strategy will see bp grow its upstream oil and gas business, focus its downstream business, and invest with increasing discipline into the transition. It builds on bp's distinct strengths and competitive advantages as an integrated energy company. There are no impacts on these financial statements related to the strategy announcements in accordance with IAS 10 'Events after the reporting period'.

14. 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 2024 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		
Rruga 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		
CBW Level 19, 181 William Street, Melbourne VIC 3000, Australia		
3725 Sharp Development Pty Ltd	Ordinary	100.00
433 Link Development Company Pty Ltd	Ordinary	100.00
892 Yarrawonga Development Pty Ltd	Ordinary	100.00
Bilby FinCo Pty Ltd	Ordinary	100.00
Bilby HoldCo Pty Ltd	Ordinary	100.00
Goorambat Landco Pty Ltd	Ordinary	100.00
Goulburn River FinCo Pty Limited	Ordinary	100.00
Goulburn River Fund Pty Limited	Ordinary	100.00
Goulburn River HoldCo 2 Pty Limited	Ordinary	100.00
Goulburn River Trust	Units	100.00
Lightsource Asset Management Australia Pty Ltd	Ordinary	100.00
Lightsource Australia SPV 2 Pty Ltd	Ordinary	100.00
Lightsource Australia SPV 3 Pty Ltd	Ordinary	100.00
Lightsource Australia SPV 4 Pty Ltd	Ordinary	100.00
Lightsource Development Services Australia Pty Ltd	Ordinary	100.00
Lightsource Energy Markets Pty Ltd	Ordinary	100.00
Lightsource Labs Australia Pty Limited	Ordinary	100.00
Lightsource LS Labs Australia Operations Pty Ltd	Ordinary	100.00
Lightsource Renewable Energy (Australia) Pty Ltd	Ordinary	100.00
Lower Wonga Solar Farm Pty Ltd	Ordinary	100.00
LS Australia Equity HoldCo1 Pty Ltd	Ordinary	100.00
LS Australia FinCo 1 Pty Ltd	Ordinary	100.00
LS Australia FinCo 2 Pty Ltd	Ordinary	100.00
LS Australia FinCo 3 Pty Ltd	Ordinary	100.00
LS Australia HoldCo 1 Pty Ltd	Ordinary	100.00
LS Land Holdings Pty Ltd	Ordinary	100.00
Sandy Creek BESS FinCo Pty Ltd	Ordinary	100.00
Sandy Creek BESS Fund Pty Ltd	Ordinary	100.00
Sandy Creek BESS HoldCo Pty Ltd	Ordinary	100.00
Sandy Creek BESS Trust	Units	100.00
Sandy Creek Solar FinCo Pty Limited	Ordinary	100.00
Sandy Creek Solar Fund Pty Limited	Ordinary	100.00
Sandy Creek Solar HoldCo 2 Pty Limited	Ordinary	100.00
Sandy Creek Solar Trust	Units	100.00
Sun Spot 3 Pty Ltd	Ordinary	100.00
Wellington LandCo Pty Ltd	Ordinary	100.00
Wellington North Solar Farm Pty Ltd	Ordinary	100.00
West Mokoan Solar Farm Pty Ltd	Ordinary	100.00
West Wyalong FinCo Pty Ltd	Ordinary	100.00
West Wyalong Fund Pty Ltd	Ordinary	100.00
West Wyalong HoldCo 2 Pty Ltd	Ordinary	100.00
West Wyalong Trust	Units	100.00
Woolooga BESS FinCo Pty Limited	Ordinary	100.00
Woolooga BESS Fund Pty Limited	Ordinary	100.00

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14. Related undertakings of the group – continued

Woolooga BESS HoldCo 2 Pty Limited	Ordinary	100.00
Woolooga BESS Trust	Units	100.00
Woolooga FinCo Pty Ltd	Ordinary	100.00
Woolooga Fund Pty Ltd	Ordinary	100.00
Woolooga HoldCo 2 Pty Ltd	Ordinary	100.00
Woolooga Trust	Units	100.00
Wunghnu Solar Farm FinCo Pty Ltd	Ordinary	100.00
Level 10, QV1 Building, 250 St Georges Terrace, Perth, WA 6000, Australia		
BP Developments Holdings 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
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	51.00
BASS NZ Sub Management Pty Ltd	Ordinary	51.00
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[a]	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
West Kimberley Fuels Pty Ltd	Ordinary	100.00
Level 9/10, 250 St Georges Terrace, Perth, WA 6000, Australia		
BP Developments Australia Pty. Ltd.	Ordinary	100.00
Austria		
Am Belvedere 10, 1100 Wien, Austria		
Alstersee 472. V V GmbH	Ordinary	100.00
Alstersee 473. V V GmbH	Ordinary	100.00
CASTROL Austria GmbH	Ordinary	100.00
Castrol Österreich Lubricants GmbH	Ordinary	100.00

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14. Related undertakings of the group – continued

Azerbaijan		
153 Neftchilar Avenue, Baku, AZ1010, Azerbaijan		
BP-AIOC Exploration (TISA) LLC	Membership Interest	65.88
TISA Education Complex LLC	Membership Interest	65.88
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		
Al Santos, 74, Andar 7 Conj 72 Sala 53, Cerqueira Cesar, Sao Paulo, 01.418-000, Brazil		
Lightsource Milagres Holding 1 S.A.	Ordinary	100.00
Alameda Santos, 74, 7th floor, suite 72, room 111, Cerqueira César, Municipality of São Paulo, São Paulo, 01418-000, Brazil		
Lightsource Bom Lugar Holding 1 S.A.	Ordinary	100.00
Lightsource Bom Lugar Holding 2 S.A.	Ordinary	100.00
Alameda Santos, 74, 7th floor, suite 72, room 43, Cerqueira César, Municipality of São Paulo, São Paulo, 01418-000, Brazil		
Lightsource Brasil Energia Renovável Participções S.A.	Ordinary	100.00
Alameda Santos, 74, 7th floor, suite 72, room 44, Cerqueira César, Municipality of São Paulo, São Paulo, 01418-000, Brazil		
Lightsource Brasil Energia Renovável Ltda	Ordinary	100.00
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, 12.399, 4° andar, cj. 41B, sala 01, São Paulo, Brazil		
Itumbiara Trading Comercio Importação e Exportação Ltda.	Ordinary	100.00
Avenida das Nações Unidas, nº 12.399, 4° andar, Brooklin Paulista, São Paulo, CEP 04578-000, Brazil		
BP Bioenergy S.A.	Ordinary	100.00
Avenida das Nações Unidas, nº 12.399, 4° andar, salas 43A e 44A , Torre C, Edifício Landmark, Brooklin Paulista, São Paulo/SP, CEP 04578-000, Brazil		
Air BP Brasil Ltda.	Ordinary	100.00
BP Biocombustíveis Ltda.	Ordinary	100.00
Avenida das Nações Unidas, nº 12.399, salas 62,63 e 64, lado B, 6° andar, Edifício Landmark, São Paulo/SP, CEP 04578-000, Brazil		
BP Comercializadora de Energia Ltda.	Ordinary	100.00
Estado do Rio Grande do Norte, Sítio Retiro, S/N, Estrada Caraúbas sentido Mirandas, Km 15, lado esquerdo, Zona Rural, Cidade de Caraúbas, CEP 59780-000, Brazil		
Lightsource Caraúbas Geração de Energia Ltda	Ordinary	100.00
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	100.00
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	100.00
Estrada Municipal Itumbiara / Chacoeira Dourada, Fazenda Jandaia, Gleba B, Goiás, Itumbiara, 75516-126, Brazil		
Itumbiara Bioenergia S.A.	Ordinary	100.00
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	100.00
Fazenda Água Amarela, S/N, Itapegipe, Minas Gerais, 38240-000, Brazil		
Itapagipe Bioenergia Ltda.	Ordinary	100.00
Fazenda Guariroba, SN, Zona Rural, Pontes Gestal, São Paulo, 15500-000, Brazil		
Guariroba Bioenergia Ltda	Ordinary	100.00
Fazenda Moema, s/n, Rural, Orindiuva, São Paulo, 15480-000, Brazil		
Moema Bioenergia S.A	Ordinary	100.00
Fazenda Recanto, Zona Rural, CEP 38.300-898, Minas Gerais, Ituiutaba, Brazil		
Ituiutaba Bioenergia Ltda.	Ordinary	100.00
Fazenda Santa Bárbara, S/N, Distrito de Zelândia, Santa Juliana, Minas Gerais, 38175-000, Brazil		
Santa Juliana Bioenergia Ltda.	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Fazenda São Bento da Ressaca, S/N, Zona Rural, Frutal, Minas Gerais, 38200-000, Brazil		
Frutal Bioenergia Ltda.	Ordinary	100.00
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 S.A.	Ordinary	100.00
Lightsource Bom Lugar IX Geração de Energia S.A.	Ordinary	100.00
Lightsource Bom Lugar V Geração de Energia S.A.	Ordinary	100.00
Lightsource Bom Lugar VI Geração de Energia S.A.	Ordinary	100.00
Lightsource Bom Lugar VII Geração de Energia S.A.	Ordinary	100.00
Lightsource Bom Lugar VIII Geração de Energia S.A.	Ordinary	100.00
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	100.00
KM 2.4 Sítio Cajueiro road - KM491 BR 116 KM 492, Caatinga Grande Zona Rural, Municipality of Abaiara, State of Ceará, 63.240.000, Brazil		
Lightsource Milagres I Geração de Energia S.A	Ordinary	100.00
Lightsource Milagres II Geração de Energia S.A	Ordinary	100.00
Lightsource Milagres III Geração de Energia S.A	Ordinary	100.00
Lightsource Milagres IV Geração de Energia S.A	Ordinary	100.00
Lightsource Milagres V Geração de Energia S.A	Ordinary	100.00
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	100.00
Rodovia GO 410, km 51 à esquerda, Fazenda Canadá, s/n, Zona Rural, Sala 01 Estado de Goiás, Edéia, 75940-000, Brazil		
Tropical Bioenergia S.A.	Ordinary	100.00
Tropical Biogás Ltda	Ordinary	100.00
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	100.00
Rodovia SP - 463 Elyeser Montenegro Magalhãe, KM 186, S/N, Zona Rural,São Paulo, Ouroeste, 15685-000, Brazil		
Ouroeste Bioenergia Ltda.	Ordinary	100.00
Rodovia TO 010 KM 20, S/N, Zona Rural, Cidade de Pedro Afonso, Tocantins, 77710-000, Brazil		
Pedro Afonso Bioenergia Ltda.	Ordinary	100.00
Rua Principal, Fazenda Recanto, Zona Rural, Caixa Postal 01, Minas Gerais, Ituiutaba, 38.300-898, Brazil		
Campina Verde Bioenergia Ltda.	Ordinary	100.00
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	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
Ocorian Corporate Services (BVI) Limited, 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
1741 Lower Water Street, Suite 600, Halifax, NS, B3J 0J2, Canada		
BP Canada Energy Group ULC	Ordinary	100.00
240 Fourth Avenue SW, Calgary AB T2P 2H8, Canada		
563916 Alberta Ltd.	Preference	33.33
Dome Beaufort Petroleum Limited	Ordinary	100.00
77 King Street West, Suite 400, Toronto, Canada		
TravelCentres Canada Corporation	Membership Interest	100.00
TravelCentres Canada Inc.	Membership Interest	100.00
TravelCentres Canada Limited Partnership	Limited Partner	100.00
900, 1959 Upper Water Street, Halifax, NS, B3J 3N2, Canada		
BP Canada Energy Development Company	Ordinary	100.00

14. Related undertakings of the group – continued

Chile		
Av. Américo Vespucio Sur No. 100, of. 1101, Las Condes, Santiago, Chile		
Burmah Chile SpA	Ordinary	100.00
China		
#4047, Room 313, Floor 3, Shanshui Tower, No. 3, Guloudong Avenue, Beijing, Miyun District, China		
Beijing BP Advanced Mobility Limited	Membership Interest	100.00
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	85.00
201-D069, No.13 and No.15 Fujia Middle Street, Nansha District, Guangzhou, China		
Guangdong Jintian Technology Co., Ltd.	Membership Interest	100.00
4-2-506, Rongchuang Rongsheng Plaza, Binhai-Zhongguancun Science and Technology Park, Tianjin Economic and Technological Development Zone, Tianjin, China		
Tianjin BP Advanced Mobility Limited	Membership Interest	100.00
501, Unit 1, Building 12, Changtang Fourth District, Fotang Town, Yiwu City, Jinhua City, Zhejiang Province		
Jinhua BP Xiaoju New Energy Co., Ltd.	Membership Interest	85.00
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	85.00
C2256, Zhongchuang Space,9-14/F, Building A, Baoye Center, No.31 Jianshe 1st Road, Qingshan District, Wuhan City, Hubei Province, China		
Wuhan BP Xiaoju New Energy Technology Co., Ltd.	Membership Interest	85.00
D21 Room 306, No.64, Shiji Village Section, Shiji Town, Guangzhou, Panyu District, China		
Guangzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	85.00
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	85.00
Fenglin West Road, Dongpu Street,Yuecheng District, Shaoxing City, Zhejiang Province, China		
Shaoxing BP Xiaoju New Energy Co., Ltd.	Membership Interest	85.00
Floor 3, Building 5, 255 Guiqiao Road, Shanghai Pilot Free Trade Zone, China		
Castrol (Shanghai) Management Co., Ltd	Membership Interest	100.00
No 833, South Guang Zhou Avenue, Guangzhou Province, Haizhu District, China		
BP Guangdong Limited	Membership Interest	90.00
No. 06-03, 5th Floor, Building 1, Modern-International Design Phase 1,Guandong Street, No. 41, Guanggu Avenue, East Lake New Technology Development Zone, Wuhan (Wuhan Free Trade Zone), Hubei Province, China		
Wuhan BP Advanced Mobility Limited	Membership Interest	100.00
No. 1, Building 29, Tang'an Community, Haihong Street, Taizhou Bay New District, Taizhou City, Zhejiang Province, China		
Taizhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	85.00
No. 302-2401, No. 6-2 Tong'an Second Road, Fushan New Area Street, Shibei District, Qingdao City, Shandong Province, China		
Qingdao BP Advanced Mobility Limited	Membership Interest	100.00
No. 3-6-23, 1st Floor, Building 7, No. 130 Xiazhongdukou, Shapingba Street, Shapingba District, Chongqing, China		
Chongqing BP Advanced Mobility Limited	Membership Interest	100.00
No. 399 Dongfeng highway, Dongping Town, Chongming District, (Dongping Economic Development, Shanghai City, China		
Shanghai Quanzhi New Energy Co., Ltd.	Membership Interest	85.00
No. 6, Floor 1, Building A, No. 2, West Tao Hong Street, Shi Ma Village, Jun He Streat, Guangzhou, China		
Guangdong Jintian New Energy Automobile Co., Ltd.	Membership Interest	100.00
No.0152, Room 16, 17, 18, 7/F, Unit 3, Building 4, Greenland Liansheng International, East of Xingxin North Road and north of Yingbin Road, Jinhuayuan Street, Guanshanhu District, Guiyang City, Guizhou Province, China		
GuiYang City BP Xiaoju New Energy Technology Co. Ltd.	Membership Interest	85.00
No.17-5, Second Floor 04, Sumitomo Homeland, Binhu District, Wuxi City, China		
Wuxi BP Xiaoju New Energy Co., Ltd.	Membership Interest	85.00
No.2, North Chuangang Road, Nangang Industrial Zone, Tianjin Economic Development Area, Tianjin, China		
Castrol (Tianjin) Lubricants Co., Ltd	Membership Interest	100.00
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	85.00
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	85.00

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14. Related undertakings of the group – continued

Room 102, No. 1, Shixin Road, Shiqiao Street, Panyu District, Guangzhou, China		
Guangzhou Jintian New Energy Technology Co., Ltd.	Membership Interest	100.00
Room 1107-2A258, Building 1, Aerospace City Center Square, Shenzhouwu Road, National Civil Aerospace Industry Base, Xi'an City, Shaanxi Province, China		
BP (Xi'an) Advanced Mobility Limited	Membership Interest	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 1703B051, 17th Floor, Building 1, Gaoxin SOHO, Yinlan Road, Science Avenue, Zhengzhou High-tech Industrial Development Zone, Henan Province		
Zhengzhou BP Advanced Mobility Limited	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	85.00
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	85.00
Room 2103, 10 Hua Xia Road, Tianhe District, Guangzhou, PR, China		
BP (Guangzhou) Advanced Mobility Limited	Ordinary	100.00
Room 215, Building #5, No. 72, Nanxiang Er Road, Guangzhou, China		
Guangzhou Jintian Linkage New Energy Technology Co., Ltd.	Membership Interest	100.00
Room 2-1-7, 1st Floor,Building 7, No.130 Xiazhong Dukou, Shapingba District, Chongqing, China		
Chongqing BP Xiaoju New Energy Co., Ltd.	Membership Interest	85.00
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	85.00
Room 2233, second floor, Aofeng Street Resettlement House #1, No. 50 Aofeng Road, Aofeng Street, Fuzhou City, Taijiang District, China		
Fujian BP Xiaoju New Energy Technology Co., Ltd	Membership Interest	85.00
Room 2245, Area G, Building 10, Yaxi International Slow City Town, Gaochun District, Nanjing City, Jiangsu Province, China		
Nanjing BP Advanced Mobility Limited	Membership Interest	100.00
Room 2302, Unit 1, Building 20, Shengtang Supreme, Luolong District, Luoyang City, Henan Province, China		
Luoyang BP Xiaoju New Energy Co., Ltd.	Membership Interest	85.00
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	85.00
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	85.00
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	85.00
Room 3122, 3rd Floor, Building 3, No. 36, Baiyang Street, Qiantang District, Hangzhou, Zhejiang Province, China		
Hangzhou BP Advanced Mobility Limited	Membership Interest	100.00
Room 3173, Building 1,No.39 Hongtu Road, Nancheng Street, Dongguan City, Guangdong Province, China		
Dongguan BP Xiaoju New Energy Co., Ltd.	Membership Interest	85.00
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	85.00
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	85.00
Room 402-12, No.90~96 Science Avenue (even), Huangpu District, Guangzhou, China		
Guangzhou Huangpu BP Xiaoju New Energy Technology Co., Ltd.	Membership Interest	85.00
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	85.00
Room 505, 5th Floor, Building 6,No. 599, Century City South Road, Chengdu High-tech Zone, China (Sichuan) Pilot Free Trade Zone, China		
Chengdu BP Advanced Mobility Limited	Membership Interest	100.00
Room 703, Building 32, No.258 Shengpu Road, Suzhou Industrial Park, China		
Suzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	85.00
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	85.00

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14. Related undertakings of the group – continued

Room 7088-594, 7th Floor, 1558 Jiangnan Road, Ningbo High-tech Zone, Zhejiang Province, China		
Ningbo BP Xiaoju New Energy Co., Ltd.	Membership Interest	85.00
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	85.00
Room 820, 8th Floor, Hilton Hotel, Platinum Bay World Trade Center, 1100, Section 3, Xiaoxiang North Road, Hunan Province, Changsha City, Yuelu District, China		
Changsha BP Advanced Mobility Limited	Membership Interest	100.00
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	85.00
Room A018, 10th Floor, Kaifeng Building, No. 188, Fuqiang Street, Yuhua District, Shijiazhuang City, Hebei Province, China		
Shijiazhuang City BP Xiaoju New Energy Technology Co. Ltd.	Membership Interest	85.00
Unit 01, 6th Floor (actual 5th), No.90 Qirong Road, China (Shanghai) Pilot Free Trade Zone, China		
BP (China) Holdings Limited	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	85.00
Colombia		
Calle 80 No.11-42 Oficina 901, Bogota, 110111, Colombia		
Castrol Colombia Ltda.	Membership Interest	100.00
GOAM 1 C.I S. A .S	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
Kampmannsgade 2. 1604 København V, Denmark		
BP Danmark A/S	Ordinary	100.00
BP OFW Danmark ApS	Ordinary	100.00
Castrol Denmark A/S	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		
1165 rue Jean-René Guilibert Gauthier de la Lauzière – CS 20583, Aix-les-Milles Cedex 02, 13290, France		
Lightsource France Development SAS	Ordinary	100.00
Lightsource France SPV 1 SAS	Ordinary	100.00
Lightsource France SPV 2 SAS	Ordinary	100.00
Lightsource France SPV 3 SAS	Ordinary	100.00
Lightsource France SPV 4 SAS	Ordinary	100.00
Lightsource France SPV 5 SAS	Ordinary	100.00
Lightsource France SPV 6 SAS	Ordinary	100.00
Lightsource France SPV 7 SAS	Ordinary	100.00
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 Metallugie Doittau	Ordinary	100.00
Société de Gestion de Dépots d'Hydrocarbures - GDH	Ordinary	100.00
SRHP	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

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14. Related undertakings of the group – continued

An der Börse 4, 30159 Hannover, Germany		
Dritte Energieversorgungsvorratsgesellschaft mbH	Ordinary	100.00
FORTAS Energie Gas GmbH	Ordinary	100.00
GETEC ENERGIE GmbH	Ordinary	100.00
GEWI GmbH	Ordinary	81.28
An der Steinkuhle 2 d-e, 39128 Magdeburg, Germany		
GETEC Daten-und Abrech-nungsmanagement GmbH	Ordinary	100.00
c/o WeWork, Kemperplatz 1, Berlin, 10785, Germany		
Lightsource Development Deutschland GmbH	Ordinary	100.00
Lightsource GP GmbH	Ordinary	100.00
Lightsource LP 1 GmbH	Ordinary	100.00
Margarete-Steiff-Straße 1-3, 24558 Henstedt-Ulzburg, Germany		
EEG Energie- Einkaufs- und Service GmbH (NEU)	Ordinary	100.00
Raffineriestraße 1, Lingen, 49808, Germany		
Lingen Green Hydrogen GmbH & Co. KG	Ordinary	100.00
Lingen Green Hydrogen Management GmbH	Ordinary	100.00
Sportallee 6, 22335 Hamburg, Germany		
TGH Tankdienst-Gesellschaft Hamburg GbR	Partnership interest	66.67
Timmerhellstsr. 28, Mülheim/Ruhr, 45478, Germany		
DHC Solvent Chemie GmbH	Ordinary	100.00
Überseeallee 1, 20457, Hamburg, Germany		
BP Energy Holdings GmbH	Ordinary	100.00
BP Europa SE[b]	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 OFW Management 1 GmbH	Ordinary	100.00
bp OFW Management 2 GmbH	Ordinary	100.00
bp OFW Management 3 GmbH	Ordinary	100.00
bp OFW Management 4 GmbH	Ordinary	100.00
TRaBP GbR	Partnership interest	75.00
Trafineo GmbH & Co. KG	Partnership interest	75.00
Trafineo Service GmbH	Ordinary	75.00
Trafineo Verwaltungs-GmbH	Ordinary	75.00
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, 15231, Chalandri, Attica, Greece		
BP Oil Hellenic S.M.S.A.	Ordinary	100.00
Castrol Hellas Single Member Societe Anonyme	Ordinary	100.00
68, Vasilisis Sofias Ave., Athens, 115 28, Greece		
AI ENERGY SINGLE MEMBER P.C.	Ordinary	100.00
Akarnanika Photovoltaic Systems Single-Member Private Company	Ordinary	100.00
Enipeas Single Member S.A.	Ordinary	100.00
Lightsource Renewable Energy Greece Development Single Member S.A.	Ordinary	100.00
Lightsource Renewable Energy Greece Projects 3 SINGLE MEMBER S.A.	Ordinary	100.00
Lightsource Renewable Greece BESS 1 S.A.	Ordinary	100.00
Lightsource Renewable Greece BESS 2 S.A.	Ordinary	100.00
Local Community of Kyrakalis, number 0, Municipality of Grevena, 51100, Greece		
Clean Energy 1 S.M.S.A.	Ordinary	100.00
Clean Energy 4 S.M.S.A.	Ordinary	100.00

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14. Related undertakings of the group – continued

Green Energy Plus 1 S.M.S.A.	Ordinary	100.00
Green Energy Plus 2 S.M.S.A.	Ordinary	100.00
Green Energy Plus 7 S.M.S.A	Ordinary	100.00
Guernsey		
Albert House, South Esplanade, St. Peter Port, GY1 1AW, Guernsey		
BP Pensions (Overseas) Limited[c]	Ordinary	100.00
Jupiter Insurance Limited	Ordinary	100.00
Hong Kong		
Room 1218,Space Wai Yip Street, 11,12, Rooftop, 133 Wai Yip Street, 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 411014, India		
BP Business Solutions India Private Limited	Ordinary	100.00
Technopolis Knowledge Park, Mahakali Caves Road, Andheri (East), Mumbai 400093, India		
BP India Private Limited	Ordinary	100.00
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, 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
Trinity House, Charleston Road, Ranelagh, Dublin, D06 C8X4, Ireland		
Lightsource Ireland Development Holdings Limited	Ordinary	100.00
Lightsource Ireland SPV 6 Limited	Ordinary	100.00
Lightsource Renewable Energy Ireland Limited	Ordinary	100.00
Italy		
Piazza Borromeo, 12, Milano, 20123, Italy		
BP Italia Holdings SpA	Ordinary	100.00
Via Gaetano De Castillia, 23, Milan, MI, 20124, Italy		
BP Italia SpA	Ordinary	100.00
Via Giacomo Leopardi 7, Milano, 20123, Italy		
Belenos s.r.l.	Ordinary	65.00
Lightsource Renewable Energy Italy Development, S.r.l.	Ordinary	100.00
Lightsource Renewable Energy Italy Finco s.r.l.	Ordinary	100.00
Lightsource Renewable Energy Italy Holdings S.r.l.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 1 s.r.l.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 10 s.r.l.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 11 S.r.l	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 12 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 13 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 14 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 15 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 16 S.R.L.	Ordinary	100.00

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14. Related undertakings of the group – continued

Lightsource Renewable Energy Italy SPV 17 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 18 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 19 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 2 s.r.l.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 20 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 21 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 22 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 23 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 24 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 25 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 26 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 27 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 28 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 29 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 30 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 31 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 32 S.R.L.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 4 s.r.l.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 8 s.r.l.	Ordinary	100.00
Lightsource Renewable Energy Italy SPV 9 s.r.l.	Ordinary	100.00
Pollon s.r.l.	Ordinary	65.00
Via Venti Settembre, 69, Palermo, 90141, Italy		
Marsala Energie S.r.l.	Ordinary	100.00
Melilli Energie S.r.l.	Ordinary	100.00
ML Energie Rinnovabili S.r.l.	Ordinary	100.00
Viale Francesco Scaduto, 2d, Palermo, 90144, Italy		
HF Solar 1 S.r.l.	Ordinary	100.00
HF Solar 10 S.r.l.	Ordinary	100.00
HF Solar 2 S.r.l.	Ordinary	100.00
HF Solar 3 S.r.l.	Ordinary	100.00
HF Solar 4 S.r.l	Ordinary	100.00
HF Solar 5 S.r.l	Ordinary	100.00
Japan		
15th Fl. Roppongi Hills Mori Tower, 10-1 Roppongi 6-chome, Minato-ku, Tokyo106-6115, Japan		
BP Energy Japan KK	Ordinary	100.00
BP Japan K.K.	Ordinary	100.00
TJKK	Ordinary	100.00
c/o Forvis Mazars Japan Co., Ltd.,Akasaka Intercity 5F, 1-11-44 Akasaka, Minato-ku, Tokyo, 107-0052, Japan		
GK Flor De Loto56	Membership Interest	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)		
#125 DD-01, 14F, 416 Hangang-daero, Jung-gu, Seoul, Korea (the Republic of)		
SK Devco Solar Power Plant Co., Ltd.	Ordinary	100.00
#125 DD-02, 14F, 416 Hangang-daero, Jung-gu, Seoul, Korea (the Republic of)		
LS Renewable Energy Co., Ltd.	Ordinary	100.00
#125 DD-03, 14F, 416 Hangang-daero, Jung-gu, Seoul, Korea (the Republic of)		
Gangjin Solar Power Plant Co., Ltd.	Ordinary	100.00
#132, 14F, 416 Hangang-daero, Jung-gu, Seoul, Korea (the Republic of)		
Lightsource Renewable Energy Development South Korea Co., Ltd	Ordinary	100.00
125 DD04, 14F, 416 Hangang-daero, Jung-gu, Seoul, 04637, Korea (the Republic of)		
Haenam Solar Power Plant Co., Ltd.	Ordinary	100.00
1304(Ocean Hill Officetel), 73 gangnam-haeanro, Dolsan-eup, Yeosu-si, Jeollanam Province, Korea (the Republic of)		
West Ocean Wind Co., Ltd.	Ordinary	55.00
19th Floor, 302, Teheran-ro, Gangnam-gu, Seoul, Korea (the Republic of)		
BP Korea Limited	Ordinary	100.00

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14. Related undertakings of the group – continued

24-1 Gunnae 3beon-gil, Wando-eup, Wando-gun, Jeollanam-do, Korea (the Republic of)		
Chunghaejin Offshore Wind Power Co., Ltd.	Ordinary	55.00
Level 2 (LS Tower), 7 Samyul 6-gil, Hupo-myeon, Uljin County, Gyeongsangbuk Province, Korea (the Republic of)		
Ilchool Offshore Wind Power Co., Ltd.	Ordinary	55.00
Level 3, 702-ho, 61-18 Odongdo-ro, Yeosu-si, Jeollanam Province, Korea (the Republic of)		
YiSunSin Offshore Wind Co., Ltd.	Ordinary	55.00
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
Mozambique		
Torres Rani, Avenida Marginal, Talhão 141, 6º andar, Maputo, Mozambique		
BP Mocambique Limitada	Ordinary	100.00
Netherlands		
Boompjes 40, NL 3011 XB, Rotterdam, Netherlands		
ConceptsnSolutions B.V.	Ordinary	87.50
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 Offshore Renewables Energy 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

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14. Related undertakings of the group – continued

FreeBees B.V.	Ordinary	100.00
Mobility Hub Nieuw Reijerwaard B.V.	Ordinary	100.00
Vaals B.V.	Ordinary	100.00
Vaals HoldCo B.V.	Ordinary	100.00
Gustav Mahlerplein 28, 1082MA, Amsterdam, Netherlands		
Lightsource Renewable Energy Netherlands Development B.V.	Ordinary	100.00
Lightsource Renewable Energy Netherlands Holdings B.V.	Ordinary	100.00
Zonneweide Liesvelden B.V.	Ordinary	100.00
Zonneweide LS 4 B.V.	Ordinary	100.00
Zonneweide LS 5 B.V.	Ordinary	100.00
Zonneweide LS 6 B.V.	Ordinary	100.00
Zonneweide LS 7 B.V.	Ordinary	100.00
Zonneweide LS 8 B.V.	Ordinary	100.00
Nijverheidsstraat 5, 7641 AB, Wierden, Netherlands		
Energie Makelaar B.V.	Ordinary	84.99
Überseeallee 1, 20457, Hamburg, Germany		
Alstersee 470. V V GmbH	Ordinary	100.00
Alstersee 471. V V GmbH	Ordinary	100.00
BP Holdings Central Europe B.V.	Ordinary	100.00
New Zealand		
Corporate Services New Zealand Limited, Level 5, 79 Queen Street, Auckland, 1010, New Zealand		
Lightsource Development Services New Zealand Limited	Ordinary	100.00
LSNZ Glorit Holdco Limited	Ordinary	100.00
LSNZ Kowhai Park EquityCo Limited	Ordinary	100.00
LSNZ Kowhai Park HoldCo Limited	Ordinary	100.00
Level 2, Stantec Building 105 Carlton Gore Road Newmarket Auckland, 1023, 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		
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
Norway		
Tjuvholmen allé 3, 0252 Oslo, Norway		
Air BP Norway AS	Membership Interest	100.00
BP Low Carbon Energy Norway Holding AS	Ordinary	100.00
BP Norway Offshore Wind SN2 Holdco AS	Ordinary	100.00
Castrol Norway AS	Ordinary	100.00
Oman		
PO Box 2309, Salalah, 211, Oman		
BP Global Investments Salalah & Co LLC	Membership Interest	100.00
Rock Garden Plaza – Phase 1 Building, PO Box 545, PC 118, Oman		
BP Duqm Hydrogen SPC	Ordinary	100.00
Special Economic Zone at Duqm (SEZAD), Oman		
BP Hydrogen Operator SPC	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

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14. Related undertakings of the group – continued

Philippines		
2nd Floor AGS Building, 446 EDSA, Makati City 1211, Phillippines		
Castrol Philippines, Inc.	Ordinary	100.00
Poland		
ul. Grzybowska 2/29, 00-131, Warszawa, Poland		
Lightsource Development Polska sp. z o.o.	Ordinary	100.00
LS 1 sp. z.o.o.	Ordinary	100.00
LS 10 sp. z o.o.	Ordinary	100.00
LS 11 sp. z o.o.	Ordinary	100.00
LS 12 sp. z o.o.	Ordinary	100.00
LS 13 sp. z.o.o.	Ordinary	100.00
LS 14 sp. z.o.o.	Ordinary	100.00
LS 2 sp. z.o.o.	Ordinary	100.00
LS 3 sp. z.o.o.	Ordinary	100.00
LS 4 sp. z.o.o.	Ordinary	100.00
LS 5 sp. z.o.o.	Ordinary	100.00
LS 6 sp. z.o.o.	Ordinary	100.00
LS 7 sp. z.o.o.	Ordinary	100.00
LS 8 sp. z o.o.	Ordinary	100.00
LS 9 sp. z.o.o.	Ordinary	100.00
RD PV Produkcja 5 Spółka Z Ograniczona Odpowiedzialnoscia	Ordinary	100.00
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
Rua Castilho, No 50, 1250-071, Lisboa, Portugal		
Coherent Modernity Lda	Membership Interest	100.00
Coloursflow - Unipessoal Lda	Quotas	100.00
Forest Constellation - Unipessoal Lda	Quotas	100.00
Ignichoice Renewable Energy V, Unipessoal LDA	Quotas	100.00
Ignidap – Energias Renováveis, Unipessoal Lda	Quotas	100.00
Lightsource Development Portugal, Unipessoal Lda	Ordinary	100.00
Lightsource Renewable Energy Portugal (HoldCo), Lda.	Membership Interest	100.00
LSbp Portugal SPV 1, Unipessoal LDA	Quotas	100.00
LSbp Portugal SPV 2, Unipessoal LDA	Quotas	100.00
Ramisun – Consultoria e Energias Renováveis, Unipessoal Lda.	Quotas	100.00
Solid Tomorrow - Energia Unipessoal Lda	Quotas	100.00
Suninger - Consultoria e Energias Renováveis, Unipessoal Lda	Quotas	100.00
Tolerantdiagonal - Lda	Ordinary	100.00
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	50.50
Romania		
District 3, 5 Halelor street, 3rd Floor, Bucharest, 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		
Berzarina str., 36, building1, Shchukino Municipal District, Moscow, 123060, Russian Federation		
Limited liability company Setra Lubricants	Membership Interest	100.00
Senegal		
Route de Ouakam x Corniche Ouest, Immeuble Alphadio Barry, Dakar, Senegal		
BP Oil Senegal S.A.	Ordinary	100.00

14. Related undertakings of the group – continued

Singapore		
7 Straits View #26-01, Marina One East Tower, 018936, Singapore		
BP Asia Pacific Pte Ltd[c]	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
8 Marina Boulevard, #05-02, Marina Bay Financial Centre, 018981, Singapore		
Lightsource Singapore Renewables Holdings Private Limited	Ordinary	100.00
Lightsource Singapore Renewables Private 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	74.97
Burmah Castrol South Africa (Pty) Limited	Ordinary; Ordinary A	100.00
ECM Markets SA (Pty) Ltd	Ordinary	74.97
Spain		
Calle Alcala numero 63, Madrid, 28014, Spain		
ISC Greenfield 12, S.L.	Ordinary	100.00
Parque FV Borealis, S.L.	Ordinary	100.00
Parque FV Polaris, S.L.	Ordinary	100.00
Calle José Ortega y Gasset, número 100, 5ª planta, Madrid, 28006, Spain		
Alejandria Power, S.L.U.	Ordinary	100.00
Caletona Servicios y Gestiones, S.L.U.	Ordinary	100.00
Castellana Power, S.L.U.	Ordinary	100.00
Castiinversiones Renovables, S.L.	Ordinary	100.00
Global Aljarafe, S.L.U	Ordinary	100.00
Global Aroche, S.L.U	Ordinary	100.00
Global Atarazana, S.L.U	Ordinary	100.00
Global Baterno, S.L.U	Ordinary	100.00
Global Baza, S.L.U	Ordinary	100.00
Global Brenes, S.L.U	Ordinary	100.00
Global Cotolengo, S.L.U	Ordinary	100.00
Global Tarquinia, S.L.U	Ordinary	100.00
Global Treviso, S.L.U	Ordinary	100.00
Global Valdenoches, S.L.U	Ordinary	100.00
Global Zalmuna, S.L.	Ordinary	100.00
Inversiones Energy Madrid, S.L.U.	Ordinary	100.00
ISC Greenfield 7, S.L.	Ordinary	100.00
Khons Sun Power, S.L.U.	Ordinary	100.00
Lightsource Europe Asset Management, SL	Ordinary	100.00
Lightsource Renewable Energy Garnacha, S.L.	Ordinary	100.00
Lightsource Renewable Energy Spain Development, SL	Ordinary	100.00
Lightsource Renewable Energy Spain Holdings, SL	Ordinary	100.00
Lightsource Renewable Energy Spain SPV 1, SL	Ordinary	100.00
Lightsource Renewable Energy Trading, SL	Ordinary	100.00
Lightsource Spain O&M, SL	Ordinary	100.00
Rin Power, S.L.U.	Ordinary	100.00
Sinfonia Solar Energy Power, S.L.U.	Ordinary	100.00
Calle Quintanadueñas, 6, (Edificio Arqborea), Madrid, 28050, Spain		
BP Energy Solutions Sociedad de Valores, S.A	Ordinary	100.00
BP Espana, S.A. Unipersonal	Ordinary	100.00
BP Gas & Power Iberia, S.A	Ordinary	100.00
BP Refined Products Trading Iberia, S.L.	Ordinary	100.00
BP Solar Espana, S.A. Unipersonal	Ordinary A; Ordinary B	100.00
Castrol España, S.L. Sociedad Unipersonal	Ordinary	100.00

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14. Related undertakings of the group – continued

Markoil, S.A. Unipersonal	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
Castellón Green Hydrogen Phase 2, S.L.	Ordinary	100.00
Castellón Green Hydrogen, S.L.	Ordinary	50.00
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		
Baarerschtrasse 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
No. 97, 18F, Songren Rd., Xinyi Dist, Taipei City, 110050, Taiwan (Province of China)		
Hui-Meng Energy Co., Ltd.	Ordinary	100.00
Lightsource Renewable Energy Development Taiwan Limited	Ordinary	100.00
Lightsource Renewable Energy SPV 1 Taiwan Limited	Ordinary	100.00
Lightsource Renewable Energy SPV 2 Taiwan Limited	Ordinary	100.00
Lightsource Renewable Energy SPV 3 Taiwan Limited	Ordinary	100.00
Lu Yang Co., Ltd	Ordinary	100.00
Thailand		
23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand		
BP - Castrol (Thailand) Limited	Ordinary	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 & Tobago LNG Holdings 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 Dogal Gaz Ticaret 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		
8th Floor, Standard Chartered Tower, Downtown, Dubai, United Arab Emirates		
BP Middle East LLC	Ordinary	100.00
United Kingdom		
1 More London Place, London, SE1 2AF, England		
Lytt Limited	Ordinary	100.00
1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom		
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
Castrol Group Holdings Limited[c]	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, England, United Kingdom		
Manormaker (Nominee No. 1) Limited	Ordinary	100.00

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14. Related undertakings of the group – continued

Manormaker (Nominee No. 2) Limited	Ordinary	100.00
Manormaker GP Limited	Ordinary	100.00
The Manormaker Limited Partnership	Membership Interest	100.00
33 Cavendish Square, London, W1G 0PW, United Kingdom		
Ropemaker Exempt Unit Trust	Membership Interest	100.00
7th Floor, 33 Holborn, London, EC1N 2HU, England, United Kingdom		
Goulburn River HoldCo 1 Limited	Ordinary	100.00
Lightsource Asset Holdings (Australia) Limited	Ordinary	100.00
Lightsource Asset Holdings (Europe) Limited	Ordinary	100.00
Lightsource Asset Holdings (Spain) Limited	Ordinary	100.00
Lightsource Asset Holdings (UK) Limited	Ordinary	100.00
Lightsource Asset Holdings (USA) Limited	Ordinary	100.00
Lightsource Asset Holdings 1 Limited	Ordinary	100.00
Lightsource Asset Holdings 2 Limited	Ordinary	100.00
Lightsource Asset Holdings 3 Limited	Ordinary	100.00
Lightsource Asset Management Limited	Ordinary	100.00
Lightsource Australia FinCo Holdings Limited	Ordinary	100.00
Lightsource Bodegas 2 Limited	Ordinary	100.00
Lightsource Bodegas 3 Limited	Ordinary	100.00
Lightsource Bodegas 4 Limited	Ordinary	100.00
Lightsource Bodegas Limited	Ordinary	100.00
Lightsource BP Renewable Energy Investments Holdings Limited	Ordinary	100.00
Lightsource BP Renewable Energy Investments Limited	Ordinary	100.00
Lightsource Brazil Holdings 1 Limited	Ordinary	100.00
Lightsource Brazil Holdings 2 Limited	Ordinary	100.00
Lightsource Commercial Rooftops Limited	Ordinary	100.00
Lightsource Construction Management Limited	Ordinary	100.00
Lightsource Corinthian Limited	Ordinary	100.00
Lightsource Cosecha Limited	Ordinary	100.00
Lightsource Development Services Limited	Ordinary	100.00
Lightsource Egypt Holdings Limited	Ordinary	100.00
Lightsource Elk Hill 2 Solar Limited	Ordinary	100.00
Lightsource Elk Hill Solar 2 Holdings Limited	Ordinary	100.00
Lightsource Finca 2 Limited	Ordinary	100.00
Lightsource Finca 3 Limited	Ordinary	100.00
Lightsource Finca Limited	Ordinary	100.00
Lightsource France Holdings UK Limited	Ordinary	100.00
Lightsource Grace 1 Limited	Ordinary	100.00
Lightsource Grace 2 Limited	Ordinary	100.00
Lightsource Grace 3 Limited	Ordinary	100.00
Lightsource Holdings 1 Limited	Ordinary	100.00
Lightsource Holdings 2 Limited	Ordinary	100.00
Lightsource Holdings 3 Limited	Ordinary	100.00
Lightsource Iberia Greenfield Holdings Limited	Ordinary	100.00
Lightsource Iberia Project Holdings Limited	Ordinary	100.00
Lightsource Impact 1 Limited	Ordinary	100.00
Lightsource Impact 2 Limited	Ordinary	100.00
Lightsource India Holdings (Mauritius) Limited	Ordinary	100.00
Lightsource India Holdings Limited	Ordinary	100.00
Lightsource India Investments (UK) Limited	Ordinary	100.00
Lightsource India Limited	Ordinary	51.00
Lightsource India Maharashtra 1 Holdings Limited	Ordinary	100.00
Lightsource India Maharashtra 1 Limited	Ordinary	100.00
Lightsource Kingfisher Holdings Limited	Ordinary	100.00
Lightsource Labs 1 Limited	Ordinary	100.00
Lightsource Manzanilla Limited	Ordinary	100.00
Lightsource Operations 1 Limited	Ordinary	100.00
Lightsource Operations 2 Limited	Ordinary	100.00
Lightsource Operations 3 Limited	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Lightsource Operations Services Limited	Ordinary	100.00
Lightsource Poland Holdings (UK) Limited	Ordinary	100.00
Lightsource Property 1 Limited	Ordinary	100.00
Lightsource Property 2 Limited	Ordinary	100.00
Lightsource Renewable Energy (India) Limited	Ordinary	100.00
Lightsource Renewable Energy Asia Pacific Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Australia Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Greece Holdings (UK) Limited	Ordinary	100.00
Lightsource Renewable Energy Greece Holdings 2 (UK) Limited	Ordinary	100.00
Lightsource Renewable Energy Greece Projects 2 Limited	Ordinary	100.00
Lightsource Renewable Energy Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Iberia Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy India Assets Limited	Ordinary	100.00
Lightsource Renewable Energy India Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy India Projects Limited	Ordinary	100.00
Lightsource Renewable Energy Italy Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Limited	Ordinary	100.00
Lightsource Renewable Energy Moristel Limited	Ordinary	100.00
Lightsource Renewable Energy Netherlands Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy New Zealand Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Poland Projects 1 Limited	Ordinary	100.00
Lightsource Renewable Energy Poland Projects 2 Limited	Ordinary	100.00
Lightsource Renewable Energy Portugal Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Portugal Projects 1 Limited	Ordinary	100.00
Lightsource Renewable Energy Portugal Projects 2 Limited	Ordinary	100.00
Lightsource Renewable Energy Tempranillo Limited	Ordinary	100.00
Lightsource Renewable Energy Verdejo Limited	Ordinary	100.00
Lightsource Renewable Global Development Limited	Ordinary	100.00
Lightsource Renewable Services Limited	Ordinary	100.00
Lightsource Renewable Taiwan UK Holdings Limited	Ordinary	100.00
Lightsource Renewable UK Development Limited	Ordinary	100.00
Lightsource Residential Rooftops (PPA) Limited	Ordinary	100.00
Lightsource Residential Rooftops Limited	Ordinary	100.00
Lightsource SPV 101 Limited	Ordinary	100.00
Lightsource SPV 108 Limited	Ordinary	100.00
Lightsource SPV 114 Limited	Ordinary	100.00
Lightsource SPV 116 Limited	Ordinary	100.00
Lightsource SPV 118 Limited	Ordinary	100.00
Lightsource SPV 126 Limited	Ordinary	100.00
Lightsource SPV 127 Limited	Ordinary	100.00
Lightsource SPV 128 Limited	Ordinary	100.00
Lightsource SPV 130 Limited	Ordinary	100.00
Lightsource SPV 138 Limited	Ordinary	100.00
Lightsource SPV 140 Limited	Ordinary	100.00
Lightsource SPV 145 Limited	Ordinary	100.00
Lightsource SPV 149 Limited	Ordinary	100.00
Lightsource SPV 151 Limited	Ordinary	100.00
Lightsource SPV 162 Limited	Ordinary	100.00
Lightsource SPV 166 Limited	Ordinary	100.00
Lightsource SPV 167 Limited	Ordinary	100.00
Lightsource SPV 171 Limited	Ordinary	100.00
Lightsource SPV 176 Limited	Ordinary	100.00
Lightsource SPV 179 Limited	Ordinary	100.00
Lightsource SPV 18 Limited	Ordinary	100.00
Lightsource SPV 182 Limited	Ordinary	100.00
Lightsource SPV 183 Limited	Ordinary	100.00
Lightsource SPV 184 Limited	Ordinary	100.00
Lightsource SPV 185 Limited	Ordinary	100.00
Lightsource SPV 189 Limited	Ordinary	100.00

14. Related undertakings of the group – continued

Lightsource SPV 19 Limited	Ordinary	100.00
Lightsource SPV 191 Limited	Ordinary	100.00
Lightsource SPV 192 Limited	Ordinary	100.00
Lightsource SPV 199 Limited	Ordinary	100.00
Lightsource SPV 201 Limited	Ordinary	100.00
Lightsource SPV 202 Limited	Ordinary	100.00
Lightsource SPV 203 Limited	Ordinary	100.00
Lightsource SPV 204 Limited	Ordinary	100.00
Lightsource SPV 206 Limited	Ordinary	100.00
Lightsource SPV 212 Limited	Ordinary	100.00
Lightsource SPV 213 Limited	Ordinary	100.00
Lightsource SPV 214 Limited	Ordinary	100.00
Lightsource SPV 215 Limited	Ordinary	100.00
Lightsource SPV 217 Limited	Ordinary	100.00
Lightsource SPV 222 Limited	Ordinary	100.00
Lightsource SPV 232 Limited	Ordinary	100.00
Lightsource SPV 233 Limited	Ordinary	100.00
Lightsource SPV 236 Limited	Ordinary	100.00
Lightsource SPV 247 Limited	Ordinary	100.00
Lightsource SPV 25 Limited	Ordinary	100.00
Lightsource SPV 258 Limited	Ordinary	100.00
Lightsource SPV 259 Limited	Ordinary	100.00
Lightsource SPV 263 Limited	Ordinary	100.00
Lightsource SPV 264 Limited	Ordinary	100.00
Lightsource SPV 286 Limited	Ordinary	100.00
Lightsource SPV 287 Limited	Ordinary	100.00
Lightsource SPV 288 Limited	Ordinary	100.00
Lightsource SPV 29 Limited	Ordinary	100.00
Lightsource SPV 35 Limited	Ordinary	100.00
Lightsource SPV 41 Limited	Ordinary	100.00
Lightsource SPV 47 Limited	Ordinary	100.00
Lightsource SPV 56 Limited	Ordinary	100.00
Lightsource SPV 60 Limited	Ordinary	100.00
Lightsource SPV 73 Limited	Ordinary	100.00
Lightsource SPV 78 Limited	Ordinary	100.00
Lightsource SPV 88 Limited	Ordinary	100.00
Lightsource SPV 91 Limited	Ordinary	100.00
Lightsource SPV 98 Limited	Ordinary	100.00
Lightsource Titan Borrower AUD Limited	Ordinary	100.00
Lightsource Titan Borrower EUR Limited	Ordinary	100.00
Lightsource Titan Borrower GBP Limited	Ordinary	100.00
Lightsource Titan Borrower USD Limited	Ordinary	100.00
Lightsource Titan Limited	Ordinary	100.00
Lightsource Trading Limited	Ordinary	100.00
Lightsource Trinidad Holdings (UK) Limited	Ordinary	100.00
Lightsource Viking 1 Limited	Ordinary	100.00
Lightsource Viking 2 Limited	Ordinary	100.00
Lightsource Viking Limited	Ordinary	100.00
Lightsource Xenium 1 Limited	Ordinary	100.00
Lightsource Xenium 2 Limited	Ordinary	100.00
Sandy Creek Solar HoldCo 1 Limited	Ordinary	100.00
Tiln Connections Ltd	Ordinary	100.00
West Wyalong HoldCo 1 Limited	Ordinary	100.00
Woolooga BESS HoldCo 1 Limited	Ordinary	100.00
Woolooga HoldCo 1 Limited	Ordinary	100.00
Breckland, Linford Wood, Milton Keynes, MK14 6GY, England, United Kingdom		
Ashford Truckstop Freehold Limited	Ordinary	100.00
Charge Your Car Limited	Ordinary A; Ordinary B	100.00
Chargemaster Limited	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Elektromotive Limited	Ordinary	100.00
C/O Bdo Llp, 5 Temple Square, Temple Street, Liverpool, L2 5RH, United Kingdom		
Autino Holdings Limited	Ordinary	100.00
Autino Limited	Ordinary	100.00
BP (Indian Agencies) Limited[c]	Ordinary	100.00
BP Exploration (Morocco) Limited	Ordinary	100.00
BP Exploration (Psi) Limited	Ordinary	100.00
BP Exploration China Limited	Ordinary	100.00
BP Exploration Personnel Company Limited	Ordinary	100.00
BP Exploration Peru Limited	Ordinary	100.00
BP Oil Llandarcy Refinery Limited	Ordinary	100.00
BP Oil Logistics UK Limited	Ordinary	100.00
BP Oil Venezuela Limited	Ordinary	100.00
BP West Aru II Limited	Ordinary	100.00
BP West Papua I Limited	Ordinary	100.00
BTC Pipeline Holding Company Limited	Ordinary	100.00
BXL Plastics Limited	Ordinary	100.00
Fosroc Expandite 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
BP (Abu Dhabi) Limited	Ordinary	100.00
BP (Barbican) Limited[c]	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 ADUA Limited	Ordinary	100.00
BP ADUA Operating Company Limited	Ordinary	100.00
BP Advanced Mobility Limited	Ordinary	100.00
BP Africa Limited[c]	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
BP Asia Pacific Holdings Limited	Ordinary	100.00
BP Australia Swaps Management Limited	Ordinary	100.00
BP Benevolent Fund Trustees Limited[c]	Ordinary	100.00
BP Biofuels Brazil Investments Limited	Ordinary	100.00
BP Biofuels Investments Limited	Ordinary	100.00
BP Capital Markets p.l.c.	Ordinary	100.00
BP Car Fleet Limited[c]	Ordinary	100.00
BP Carbon Trading Limited	Ordinary	100.00
BP CCUS UK LTD	Ordinary	100.00
BP CCUS UK NEP Limited	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 Eta Holdings Limited	Ordinary	100.00
BP Exploration (Alpha) Limited	Ordinary	100.00
BP Exploration (Azerbaijan) Limited	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

BP Exploration (Caribbean) 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 (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 Company (Middle East) Limited	Ordinary	100.00
BP Exploration Indonesia Limited	Ordinary	100.00
BP Exploration Libya Limited	Ordinary	100.00
BP Exploration Mediterranean 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 Express Shopping Limited	Ordinary	100.00
BP Finance p.l.c.	Ordinary	100.00
BP Gamma Holdings Limited[c]	Ordinary	100.00
BP Gas & Power Investments Limited	Ordinary	100.00
BP Gas Marketing Limited	Ordinary	100.00
BP Global Investments Limited[c]	Ordinary	100.00
BP Global Solutions Limited	Ordinary	100.00
BP Greece Limited	Ordinary	100.00
BP Holdings Canada Limited[c]	Ordinary	100.00
BP Holdings Iraq Ltd	Ordinary	100.00
BP Holdings North America Limited[c]	Ordinary; Cumulative redeemable preference	100.00
BP Hydrogen and CCS Development Company Limited	Ordinary	100.00
BP Indonesia Investment Limited	Ordinary	100.00
BP Integrated Solutions Limited	Ordinary	100.00
BP International Limited[c]	Ordinary	100.00
BP Investment Management Limited	Ordinary	100.00
BP Investments Asia Limited	Ordinary	100.00
BP Iota Holdings Limited	Ordinary	100.00
BP Iran Limited	Ordinary	100.00
BP Kappa Holdings Limited	Ordinary	100.00
BP Karabagh Limited	Ordinary	100.00
BP Karabagh Operating Company Limited	Ordinary	100.00
BP Koppa Limited	Ordinary	100.00
BP Kuwait Limited	Ordinary	100.00
BP Lambda Holdings Limited	Ordinary	100.00
BP Low Carbon Development Company Limited	Ordinary	100.00
BP Marine Limited	Ordinary	100.00
BP Mauritania Investments Limited	Ordinary	100.00
BP Middle East Limited[c]	Ordinary	100.00
BP Mocambique Limited	Ordinary	100.00
BP New Ventures Middle East Limited	Ordinary	100.00
BP North East Offshore Wind Limited	Ordinary	100.00
BP NZT Power Holdings Limited	Ordinary	100.00
BP Oil International Limited	Ordinary	100.00
BP Oil UK Limited	Ordinary; Non-cumulative non-redeemable preference shares	100.00
BP Oil Vietnam Limited	Ordinary	100.00
BP Oil Yemen Limited	Ordinary	100.00
BP Oman H2 Limited	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

BP Pension Escrow Limited	Ordinary	100.00
BP Pension Trustees Limited[c]	Ordinary	100.00
BP Pensions Limited[c]	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 A; Ordinary B	75.00
BP Poseidon Limited	Ordinary	100.00
BP Properties Limited[c]	Ordinary	100.00
BP Retail Properties Limited	Ordinary	100.00
BP Russian Investments 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 Theta Holdings Limited	Ordinary	100.00
BP UK Fatima Limited	Ordinary	100.00
BP UK Retained Holdings Limited	Ordinary	100.00
BP Zeta Holdings Limited	Ordinary	100.00
BP+Amoco International Limited[c]	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
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
Energy Company of Kirkuk 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
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
HyGreen Teesside Limited	Ordinary	100.00
Iraq Petroleum Company Limited	Ordinary	100.00
Kenilworth Oil Company Limited[c]	Ordinary	100.00
Low Carbon Energy Holding Company Limited	Ordinary	100.00
Low Carbon Friends Limited	Ordinary	100.00
Lubricants UK Limited	Ordinary	100.00
Net Zero Teesside Power Holdings Limited	Ordinary	75.00
Net Zero Teesside Power Limited	Ordinary	75.00
Open Energi Limited	Ordinary	100.00
Pearl River Delta Investments Limited	Ordinary	100.00
Puls8 Ltd	Ordinary	100.00
Ropemaker Deansgate Limited	Ordinary	100.00
Ropemaker Properties Limited	Ordinary	100.00
Shafag (Jabrayil) Solar Limited	Ordinary	100.00
Snowmass Holdings Limited	Ordinary	100.00
The BP Share Plans Trustees Limited[c]	Ordinary	100.00
Viceroy Investments Limited	Ordinary	100.00
Regus Business Centre, Cromac Square, Belfast, BT2 8LA, Northern Ireland, United Kingdom		

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14. Related undertakings of the group – continued

Lightsource Renewable Energy (NI) Limited	Ordinary	100.00
Lightsource SPV 266 (NI) Limited	Ordinary	100.00
Lightsource SPV 267 (NI) Limited	Ordinary	100.00
Lightsource SPV 268 (NI) Limited	Ordinary	100.00
Lightsource SPV 269 (NI) Limited	Ordinary	100.00
Lightsource SPV 270 (NI) Limited	Ordinary	100.00
Lightsource SPV 271 (NI) Limited	Ordinary	100.00
Lightsource SPV 272 (NI) Limited	Ordinary	100.00
Lightsource SPV 273 (NI) Limited	Ordinary	100.00
Lightsource SPV 274 (NI) Limited	Ordinary	100.00
Lightsource SPV 275 (NI) Limited	Ordinary	100.00
Lightsource SPV 276 (NI) Limited	Ordinary	100.00
Lightsource SPV 277 (NI) Limited	Ordinary	100.00
Lightsource SPV 278 (NI) Limited	Ordinary	100.00
Lightsource SPV 279 (NI) Limited	Ordinary	100.00
Lightsource SPV 280 (NI) Limited	Ordinary	100.00
Lightsource SPV 281 (NI) Limited	Ordinary	100.00
Lightsource SPV 282 (NI) Limited	Ordinary	100.00
Lightsource SPV 283 (NI) Limited	Ordinary	100.00
Lightsource SPV 284 (NI) Limited	Ordinary	100.00
Lightsource SPV 285 (NI) Limited	Ordinary	100.00
Technology Centre, Whitchurch Hill, Pangbourne, Reading, RG8 7QR, United Kingdom		
Castrol Limited	Ordinary	100.00
United States		
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
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
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

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

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
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
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
2595 Interstate Drive, Suite 103, Harrisburg, PA 17110, United States		
PEI Power II, LLC	Membership Interest	100.00
PEI Power 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
2908 Poston Avenue, Nashville, TN 37203, United States		
CERF Shelby, LLC	Membership Interest	50.00
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
334, North Senate Avenue, Indianapolis, IN, 46204-1708, United States		
BP Corporation North America Inc.	Ordinary	100.00
3410 Belle Chase Way, Suite 600, Lansing, MI, 48911, United States		
Canton Renewables, LLC	Membership Interest	50.00
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, PA, 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
501 Westlake Park Boulevard, TX 77079, Houston, United States		
BP Hardin Energy Holding Company LLC	Membership Interest	100.00
7 St. Paul Street, Suite 820, Baltimore MD 21202, United States		
TA HQ LLC	Membership Interest	100.00
TA Ventures LLC	Membership Interest	100.00
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, United States		
Model City Energy, LLC	Membership Interest	100.00

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14. Related undertakings of the group – continued

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, United States		
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
c/o Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808, United States		
AH Medora LFG, LLC	Membership Interest	100.00
AHJRLLFG, LLC	Membership Interest	100.00
AHMLFG, 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
Arche Energy Project Holdings, 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
Astro Solar Investor 2, LLC	Membership Interest	100.00
Astro Solar Transfer Holdings, LLC	Class C Membership Interest	100.00
Beacon Wind Land LLC	Membership Interest	100.00
Beacon Wind LLC	Membership Interest	100.00
Big Elk Solar, LLC	Membership Interest	100.00
Biofuels Coyote Canyon Biogas, LLC	Membership Interest	100.00
BioFuels San Bernardino Biogas, LLC	Membership Interest	100.00
Birch Solar 1, LLC	Membership Interest	100.00
Canal Road Solar, LLC	Membership Interest	100.00
Cefari RNG OKC, LLC	Membership Interest	50.00
Champion Solar 1, LLC	Membership Interest	100.00
Cherry Island Renewable Energy, LLC	Membership Interest	100.00
Chester Solar Energy, LLC	Membership Interest	100.00
CII Methane Management III, LLC	Membership Interest	100.00
CII Methane Management IV, LLC	Membership Interest	100.00
Concord Solar Class B, LLC	Membership Interest	100.00
Concord Solar Construction Holdings, LLC	Membership Interest	100.00
Concord Solar Construction, LLC	Membership Interest	100.00
Concord Solar Holdings 1, LLC	Membership Interest	100.00
Concord Solar Holdings 2, LLC	Membership Interest	100.00
Concord Solar Holdings, LLC	Membership Interest	100.00
Cottontail Solar 3, LLC	Membership Interest	100.00
Cottontail Solar 4, LLC	Membership Interest	100.00
Cottontail Solar 7, LLC	Membership Interest	100.00
Cottontail Solar 9, LLC	Membership Interest	100.00
Crawford Solar, LLC	Membership Interest	100.00
Crossvine Solar 1, LLC	Membership Interest	100.00

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Crossvine Solar Holdings, LLC	Membership Interest	100.00
Desert Pine Energy Center, LLC	Membership Interest	100.00
Driver Solar Holdings, LLC	Membership Interest	100.00
Driver Solar, LLC	Membership Interest	100.00
EIF KC Landfill Gas, LLC	Membership Interest	100.00
Element Markets Renewable Natural Gas, LLC	Membership Interest	100.00
Elk Hill Solar 1 Holdings, LLC	Membership Interest	100.00
Elk Hill Solar 1 Storage, LLC	Membership Interest	100.00
Elk Hill Solar 1, LLC	Membership Interest	100.00
Elk Hill Solar 2 Holdings, LLC	Membership Interest	100.00
Elk Hill Solar 2, LLC	Membership Interest	100.00
Emerald City Renewables LLC	Membership Interest	100.00
Endurance Solar Holdings 1, LLC	Membership Interest	100.00
Endurance Solar Holdings 2, LLC	Membership Interest	100.00
Endurance Solar Holdings, LLC	Membership Interest	100.00
Endurance Solar Investor 1, LLC	Membership Interest	100.00
Endurance Solar Investor 2, LLC	Membership Interest	100.00
Endurance Solar Manager, LLC	Membership Interest	100.00
Endurance Solar Transfer Holdings, LLC	Membership Interest	100.00
Falcon Lake Storage, LLC	Membership Interest	100.00
Fiddle Leaf Solar, LLC	Membership Interest	100.00
Granite Hill Solar Land Holdings, LLC	Membership Interest	100.00
Granite Hill Solar, 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
Inverness Solar, LLC	Membership Interest	100.00
Jones City Energy Storage, LLC	Membership Interest	100.00
Jones City Solar II, LLC	Membership Interest	100.00
Jones City Solar, LLC	Membership Interest	100.00
Juliet Energy Project, LLC	Membership Interest	100.00
Kirkham Solar Farms I, LLC	Membership Interest	100.00
Kirkham Solar Farms II, LLC	Membership Interest	100.00
LES Development LLC	Membership Interest	100.00
LES Operations Services LLC	Membership Interest	100.00
LES Renewable NG LLC	Membership Interest	100.00
Lightsource Beacon 2, LLC	Membership Interest	100.00
Lightsource Beacon 3, LLC	Membership Interest	100.00
Lightsource Beacon Holdings, LLC	Membership Interest	100.00
Lightsource Beacon, LLC	Membership Interest	100.00
Lightsource Osprey Holdings A, LLC	Membership Interest	100.00
Lightsource Osprey Holdings B, LLC	Membership Interest	100.00
Lightsource Renewable Energy Asset Holdings 1, LLC	Membership Interest	100.00
Lightsource Renewable Energy Asset Management Holdings, LLC	Membership Interest	100.00
Lightsource Renewable Energy Asset Management, LLC	Membership Interest	100.00
Lightsource Renewable Energy Assets Holdings, LLC	Membership Interest	100.00
Lightsource Renewable Energy Austin Holdings, LLC	Membership Interest	100.00
Lightsource Renewable Energy Development, LLC	Membership Interest	100.00
Lightsource Renewable Energy Management, LLC	Membership Interest	100.00
Lightsource Renewable Energy Operations, LLC	Membership Interest	100.00
Lightsource Renewable Energy Services Holdings, LLC	Membership Interest	100.00
Lightsource Renewable Energy Services, Inc.	Ordinary	100.00
Lightsource Renewable Energy Spares, LLC	Membership Interest	100.00
Lightsource Renewable Energy Trading, LLC	Membership Interest	100.00
Lightsource Renewable Energy US, LLC	Membership Interest	100.00
LSBP NE Development, LLC	Membership Interest	100.00

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14. Related undertakings of the group – continued

Mavrix, LLC	Membership Interest	50.00
Mayapple Solar Holdings 1, LLC	Membership Interest	100.00
Mayapple Solar Holdings, LLC	Membership Interest	100.00
Mayapple Solar, LLC	Membership Interest	100.00
Merrillville Solar Holdings, LLC	Membership Interest	100.00
Merrillville Solar Land Holdings, LLC	Membership Interest	100.00
Merrillville Solar, LLC	Membership Interest	100.00
Mound Creek Storage, LLC	Membership Interest	100.00
Mountain Daisy Solar, LLC	Membership Interest	100.00
Mountain Holly Solar, LLC	Membership Interest	100.00
Mowata Solar, LLC	Membership Interest	100.00
Osprey Solar Holdings A, LLC	Membership Interest	100.00
Osprey Solar Holdings B, LLC	Membership Interest	100.00
Paper Shell Solar 1, LLC	Membership Interest	100.00
Peacock Energy Project Holdings, LLC	Membership Interest	100.00
Peony Solar 1, LLC	Membership Interest	100.00
Petro Franchise Systems LLC	Membership Interest	100.00
Pikes Peak Energy Storage Holdings, LLC	Membership Interest	100.00
Pikes Peak Energy Storage, LLC	Membership Interest	100.00
Pine Burr Solar 1, LLC	Membership Interest	100.00
Pine Cone Solar 2, LLC	Membership Interest	100.00
Pine Cone Solar 3, LLC	Membership Interest	100.00
Pine Cone Solar, LLC	Membership Interest	100.00
Poplar Solar 1, LLC	Membership Interest	100.00
RNG Moovers LLC	Class B Membership Interest	95.00
Rochelle Energy LLC	Membership Interest	100.00
Roscoe Solar, LLC	Membership Interest	100.00
Saturn Renewables Holdings LLC	Membership Interest	50.00
Shorebird Solar, LLC	Membership Interest	100.00
Snowdrop Solar, LLC	Membership Interest	100.00
South Shelby RNG, LLC	Membership Interest	50.00
Starr Solar Ranch 1, LLC	Membership Interest	100.00
Starr Solar Ranch LLC	Membership Interest	100.00
Sycamore Trail Land Holdings, LLC	Membership Interest	100.00
Sycamore Trail Solar, LLC	Membership Interest	100.00
TA Franchise Systems LLC	Membership Interest	100.00
TA Operating LLC	Membership Interest	100.00
TA Operating Montana LLC	Partnership interest	100.00
TAI 1 LLC	Membership Interest	100.00
Theta Solar US Holdings B, LLC	Membership Interest	100.00
Timberline Energy, LLC	Class A Membership Interest	100.00
Trinity River Solar 1, LLC	Membership Interest	100.00
TX Gulf Solar 1, LLC	Membership Interest	100.00
White Trillium Solar, LLC	Membership Interest	100.00
Whitetail Solar 6, LLC	Membership Interest	100.00
Zeus Renewables LLC	Membership Interest	100.00
Zimmerman Energy LLC	Membership Interest	100.00
Corporation Service Company 1127 Broadway Street NE, Suite 310 Salem, OR, 17110, United States		
Finley BioEnergy, LLC	Membership Interest	100.00
Corporation Service Company, 100 Shockoe Slip,2nd Floor, Richmond,VA,23219, VA, 23219, United States		
Collegiate Clean Energy, LLC	Membership Interest	100.00
INGENCO Wholesale Power, L.L.C.	Membership Interest	100.00
Corporation Service Company, 2626 Glenwood Avenue, Suite 550, Raleigh, NC, 27608, United States		
Big Run Power Producers, LLC	Membership Interest	100.00
Corporation Service Company, 8825 N. 23rd Avenue, Suite 100, Phoenix, Arizona, 85021		
Draconis Energy Project, LLC	Membership Interest	100.00
Corporation Trust Center, 1209 Orange Street, Wilmington, DE, 19801, United States		
AE Cedar Creek Holdings LLC	Membership Interest	100.00

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

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 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 Overseas Exploration Company	Ordinary	100.00
Amoco Properties Incorporated	Ordinary	100.00
Amoco Remediation Management Services Corporation	Ordinary	100.00
Amoco Research Operating Company	Ordinary	100.00
Amoco Somalia Petroleum Company	Ordinary	100.00
Amoco Sulfur Recovery Company	Ordinary	100.00
Amprop, Inc.	Ordinary	100.00
Anaconda Arizona, Inc.	Ordinary	100.00
Archaea Energy 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 Midcon LLC	Membership Interest	100.00
ARCO Unimar Holdings LLC	Membership Interest	100.00
Artemisia Geothermal Resources Inc.	Ordinary	100.00
Atlantic Richfield Company	Ordinary; Preference	100.00
Azule Energy US Gas LLC	Membership Interest	50.00
Beacon Wind Holdings LLC	Membership Interest	100.00
Blue Pier Energy Solutions LLC	Membership Interest	100.00
Blueprint Power Technologies LLC	Membership Interest	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	Membership Interest	100.00
BP Argentina Holdings LLC	Membership Interest	100.00
BP Berau Ltd.	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 Atlantic Offshore Wind Holdings LLC	Membership Interest	100.00
BP Central Atlantic Offshore Wind LLC	Membership Interest	100.00
BP Central Pipelines LLC	Membership Interest	51.00
BP Chemical Remediation Holdings LLC	Membership Interest	100.00

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14. Related undertakings of the group – continued

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 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 Latin America LLC	Membership Interest	100.00
BP Latin America Upstream Services Inc.	Ordinary	100.00
BP Louisiana Energy Park LLC	Membership Interest	100.00
BP Lubricants USA Inc.	Ordinary	100.00
BP Mariner Holding Company LLC	Membership Interest	100.00
BP Midstream Partners GP LLC	Membership Interest	100.00
BP Midstream Partners Holdings LLC	Membership Interest	100.00
BP Midstream Partners LP	Ordinary	100.00
BP Midwest Product Pipelines Holdings LLC	Membership Interest	51.00
BP Northwest Offshore Wind Holdings LLC	Membership Interest	100.00
BP Northwest Offshore Wind LLC	Membership Interest	100.00
BP Nutrition Inc.	Ordinary	100.00
BP Offshore Pipelines Company LLC	Membership Interest	100.00
BP Offshore Response Company LLC	Membership Interest	100.00
BP Offshore Wind America Development LLC	Membership Interest	100.00
BP Offshore Wind America Holding Company LLC	Membership Interest	100.00
BP Offshore Wind America 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 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 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
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

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14. Related undertakings of the group – continued

Flat Ridge Interconnection LLC	Membership Interest	57.20
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
IRGA Holdings	Membership Interest	100.00
Ken-Chas Reserve Company	Ordinary	100.00
Lightning Renewables, LLC	Membership Interest	60.00
Mardi Gras Transportation System Company 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
Remediation Management Services Company	Ordinary	100.00
Richfield Oil Corporation	Ordinary	100.00
Rolling Thunder I Power Partners, LLC	Membership Interest	100.00
Sherbino Mesa I Land Investments LLC	Membership Interest	100.00
Southern Ridge Pipeline Holding Company	Ordinary	100.00
Thorntons LLC	Membership Interest	100.00
TLK 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
Westlake Houston Development, LLC	Membership Interest	100.00
Whiting Clean Energy, Inc.	Membership Interest	100.00
Uruguay		
Dr. Luis Bonavita 1294, Oficina 2302, Montevideo, Uruguay		
BP Bioenergy Montevideo S.A.	Ordinary	100.00
Viet Nam		
9th Floor, 22-36 Nguyen Hue Street, 57-69F Dong Khoi Street, District 1, Ho Chi Minh City, Viet Nam		
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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14. 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 Ingeniero Emilio Mitre 574 Ciudad de Campana Provincia de Buenos Aires Argentina		
Lition Energy Holding Argentina S.A.U.	Ordinary	35.00
Av. Leandro N. Alem 1180, piso 11°, Buenos Aires, Argentina		
Field Services Enterprise S.A.	Ordinary	50.00
Lithos Desarollos Energeticos S.A.	Ordinary	50.00
Lithos Energia S.A.	Ordinary	35.00
Lithos Minerales Del Norte S.A.	Ordinary	31.50
Lithos Recursos Mineros S.A.	Ordinary	35.00
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
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
Juramento 433, Salta, PRovincia de Salta, Argentina		
Alqa Lithium S.A.	Ordinary	35.00
Lavalle 190, piso 6 Depto L, Buenos Aires, Argentina		
Vientos Patagonicos Chubut Norte III S.A.	Ordinary	24.50
Vientos Sudamericanos Chubut Norte IV S.A.	Ordinary	24.50
O´Higgins N° 194, Rio Grande, Argentina		
Pan American Fueguina S.A.	Ordinary	50.00
Pan American Sur S.A.	Ordinary	50.00
San Martin 140, Piso 2, Buenos Aires, Argentina		
Central Dock Sud S.A.	Ordinary	50.00
Australia		
11 Lagoon Court, Samford Valley, QLD 4520, Australia		
Australasian Lubricants Manufacturing Company Pty Ltd	Ordinary A	50.00
34 Kent Road, Mascot, NSW 2020, Australia		
5B Holdings Pty Limited	Preference Series B (27.47%)	9.80
390, Suite 4;Level 18, St Kila Road, Melbourne, VIC, 3004, Australia		
Australian Terminal Operations Management Pty Ltd	Ordinary	50.00
Brookfield Place Tower II, Level 10, 123 St Georges Terrace Perth, WA 6000, Australia		
Australian Renewable Energy Hub Pty Ltd	Ordinary	63.57
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
Suite 8.02, 28 O'Connell Street, Sydney, New South Wales 2000, Australia		
XPANSIV Limited	Ordinary (18.87%); Preference Series A (26.16%)	19.86
Austria		
Am Tankhafen 4, 4020 Linz, Austria		
TLM Tanklager Management GmbH	Membership Interest	49.00

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14. Related undertakings of the group – continued

Innsbrucker Bundesstraße 95, 5020 Salzburg, Austria		
Salzburg Fuelling GmbH	Membership Interest	50.00
Radlpaßstraße 6, 8502 Lannach, Austria		
Erdol-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 (Plurinational State of)		
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 (Plurinational State of)		
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
Avenida Atlântica, no. 1.130, 2nd floor (part), Copacabana,RJ, Rio de Janeiro, 22021-000, Brazil		
NFX Combustíveis Marítimos Ltda.	Ordinary	50.00
Avenida Paris, 4077, Suite 3, Cascata,São Paulo State, Paulínia, 13046-061, Brazil		
Terminal de Combustiveis Paulinia S.A.	Ordinary	50.00
Fazenda Saco Dantas, S/N, Área 3 e Área 4, Praia do Açu, São João da Barra, Rio de Janeiro, 28.200-000, Brazil		
UTE GNA II Geração de Energia S.A.	Ordinary	33.50
No. 804, 5th floor, Glória, Rio de Janeiro, Rio de Janeiro, 22210-010, Brazil		
Gas Natural Açu Infraestrutura S.A.	Ordinary	27.91
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
Rodovia Doutor Mendel Steinbruch 10.800, Distrito Industrial, Maracanau, 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
Rua Funchal 418, 24 andar, conjunto 2401C, parte 12, Vila Olimpia, Sao Paulo, Estado de Sao Paulo, CP 04551-060, Brazil		
Novo Horizonte Holding I Ltda.	Quotas	50.00
Novo Horizonte Holding II Ltda.	Ordinary	50.00
Pan American Energy Comercializadora De Energia Ltda.	Ordinary	50.00
Ventos De Sao Vigilio Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Vladimir Energias Renovaveis S.A.	Ordinary	50.00
Rua Manoel da Nóbrega n°1280, 10° andar, Sao Paulo, Sao Paulo, 04001-902, Brazil		
Pan American Energy do Brasil Ltda.	Membership Interest	50.00
Rua Voluntários da Pátria, No. 113, 11 floor, Botafogo, 22.270-000, Brazil		
Açu Trucked LNG S.A.	Membership Interest	30.00
Gas Natural Acu S.A.	Ordinary	30.00
Canada		
#3, 10524 42nd Street SE,Calgary AB, Canada		
Cold Bore Technology Inc	Series C preferred stock (48.65%)	12.84
2105 Commissioner Street, Vancouver, BC, V5L 1A4, Canada		
Saltworks Technologies Inc	Series A4 preferred (100.00%)	4.67

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14. Related undertakings of the group – continued

Cayman Islands		
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
Georgian Pipeline Company	Ordinary	30.37
South Caucasus Pipeline Company Limited	Membership Interest	29.99
South Caucasus Pipeline Holding Company Limited	Membership Interest	29.99
South Caucasus Pipeline Option Gas Company Limited	Ordinary	29.99
The Baku-Tbilisi-Ceyhan Pipeline Company	Membership Interest	30.10
PO Box 472, 2nd Floor, Harbour Place, 103 South Church Street, George Town, KY1-1106, Cayman Islands		
R&B Technology Holding CO., LTD	Series B Anti-Dilution (13.33%); Series B Internal Ext (40.00%); Preference Series A (78.95%); Preference Series B+ (67.21%)	27.16
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		
#1812, Level 17, 162 Nansha Street Gangqian Avenue South, Nansha District, Guangzhou, China		
Guangzhou Gangfa Petrochemical Terminal Co. Ltd.	Membership Interest	20.00
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
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
A3#608, Dongjiang Commercial Center, #599 Eerduosi Road, Free Trade Zone (Dongjiang Free Trade Zone), China		
Xin Ying Energy Marketing Co., Ltd.	Membership Interest	50.00
China, Shanghai, Xuhui District, Panyu Road 1028# 1109 room		
Castrol (Shanghai) Auto Service Technology Ltd	Ordinary	65.00
Floor 7, 1, Jichang Avenue, Shenzhen City, Guangdong Province, China		
Shenzhen Cheng Yuan Aviation Oil Company Limited	Membership Interest	25.00
No. B933, 9-14/F Office, Building A, Baoye Center, NO.31 JIA, China		
Castrol DongFeng Lubricant Co., Ltd	Membership Interest	50.00
ROOM 1022, BUILDING 1, NO. 40 CHENGMEN ROAD, DAMEN TOWN, DONGTOU DISTRICT, WENZHOU CITY, ZHEJIANG PROVINCE, P.R.CHINA, China		
Zhejiang Yingneng LNG Company Ltd.	Membership Interest	51.00
Room 526, No.13,Longxue Avenue middle, Nansha District, Guangzhou, China		
BP Guangzhou Development Oil Products Company Limited	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
Trucking Loading Station of Guangdong Dapeng LNG, Pingtou Corner, Xiasha Village, Dapeng Street, Dapeng New District, Shenzhen, China		
Shenzhen Dapeng LNG Marketing Company Limited	Membership Interest	30.00
Cuba		
Calle 6 No 319, esq 5ta. Ave., Miramar, Playa, La Habana, Cuba		
Castrol Cuba S.A.	Ordinary	50.00
Cyprus		
90 Archiepiskopou str, Dromolaxia – Meneou, 7020 Larnaca, Cyprus		
LCA Aviation Fuelling Systems Limited	Ordinary	35.00
Denmark		
GA Centervej 1, Billund, DK-7190, Denmark		
Billund Refuelling I/S	Membership Interest	50.00
Kastrup Lufthavn, 2770 Kastrup, Denmark		
Danish Refuelling Services I/S	Membership Interest	50.00

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14. Related undertakings of the group – continued

Danish Tankage Services I/S	Membership 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	50.00
85 El Nasr Road, Cairo, Egypt		
Natural Gas Vehicles Company "NGVC"	Ordinary	40.00
Al Shaheed St., Nasr City, Cairo, Egypt		
El Burg Offshore Company (EBOC)	Ordinary	20.00
El Temsah Petroleum Company "PETROTEMSAH"	Ordinary	25.00
Mediteranean Gas Co. "MEDGAS"	Ordinary	25.00
Building No. 349 & 351, Third Sector of City Centre, Fifth Settlement, New Cairo, Egypt		
United Gas Derivatives Company "UGDC"	Ordinary	33.33
Plot no 212, 2nd Sector, 5th Settlement,New Cairo, Egypt		
North Damietta Petroleum Company "PETRODAMIETTA"	Ordinary	25.50
North El Burg Petroleum Company "PETRONEB"	Ordinary	25.00
Pharaonic Petroleum Company "PhPC"	Ordinary	25.00
France		
1 Place Gustave Eiffel, Rungis, 94150, France		
Société d'Avitaillement et de Stockage de Carburants Aviation "SASCA"	Membership Interest	40.00
142 Av, Yves Farge, Saint-Pierre-des-Corps, 37700, France		
Depot Petrolier De Saint-Pierre Des Corps D.P.S.P.C.	Membership Interest	20.00
27 Route du Bassin Numéro 6, Gennevilliers, 92230, France		
Société de Gestion de Produits Pétroliers - SOGEPP	Ordinary	37.00
3 Rue des Vignes, Aéroport Roissy Charles de Gaulle, Tremblay en France, 93290, France		
Fuelling Aviation Service - FAS	Membership Interest	50.00
562 Avenue du Parc de l'Ile, Nanterre, 92000, France		
Entrepot petrolier de Chambery	Ordinary	32.00
65 Rue d'Italie, Colombier-Saugnieu, 69124, France		
Stockage de Carburant d'Aviation Lyon	Membership Interest	40.00
Aeroport Bale Mulhouse, Saint-Louis, 68300, France		
Stockage de Carburant d'Aviation	Membership Interest	40.00
Aeroport Toulouse-Blagnac, Blagnac, 31700, France		
Stockage de Carburant d'Aviation Toulouse	Membership Interest	40.00
Germany		
Am Borsigturm 68, Berlin, 13507, Germany		
Service4Charger Holding GmbH	Preference Series A (75.00%)	19.88
Am Stadthafen 60, 45881 Gelsenkirchen, Germany		
TransTank GmbH	Ordinary	50.00
An der Börse 4, 30159 Hannover, Germany		
Getigy GmbH	Ordinary	51.00
An der Braker Bahn 22, 26122 Oldenburg, Germany		
Klaus Köhn GmbH	Ordinary	50.00
Köhn & Plambeck GmbH & Co. KG	Partnership interest	50.00
Brunnenstraße 19-21, Berlin, 10119, Germany		
Digital Charging Solutions GmbH	Membership Interest	33.33
Flughafenstraße 100, 90411, Nürnberg, Germany		
TGN Tankdienst-Gesellschaft Nurnberg GbR	Membership Interest	33.30
Godorfer Hauptstraße 186, 50997 Köln, Germany		
Rhein-Main-Rohrleitungstransportgesellschaft mbH	Ordinary	35.00
Hermann-Oberth-Str. 23, D-85640 Putzbrunn, Germany		
Phelas GmbH	Seed (28.13%)	11.04
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

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14. Related undertakings of the group – continued

Lingsforter Str. 21, Straelen, 47638, Germany		
Tecklenburg GmbH	Ordinary	50.00
Luisenstraße 5 a, 26382 Wilhelmshaven, Germany		
Ammenn GmbH	Ordinary	50.00
Kurt Ammenn GmbH & Co. KG	Partnership interest	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	Membership 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	Membership Interest	33.00
Hamburg Fuelling Services (HFS) GbR	Partnership interest	50.00
Hamburg Tank Service (HTS) GbR	Partnership interest	33.00
Langenhagen Fuelling Services (LFS) GbR	Partnership interest	50.00
Tanklager-Gesellschaft Hannover-Langenhagen (TGHL) GbR	Partnership interest	50.00
TGK Tanklagergesellschaft Koln-Bonn	Partnership interest	25.00
Turbo Fuel Services Sachsen (TFSS) GbR	Partnership interest	20.00
St.-Cajetan-Str. 43, 81669 München, Germany		
Coulomb GmbH	Ordinary	50.00
Enbase Power GmbH	Ordinary	37.45
Steindamm 55, 20099 Hamburg, Germany		
GVÖ Gebinde-Verwertungsgesellschaft der Mineralölwirtschaft mbH	Ordinary	20.36
Überseeallee 1, 20457, Hamburg, Germany		
Flughafen Hannover Pipeline Verwaltungsgesellschaft mbH	Ordinary	50.00
Flughafen Hannover Pipelinegesellschaft mbH & Co. KG	Partnership interest	50.00
Wesermünder Straße 1, 27729 Hambergen, Germany		
Tecklenburg GmbH & Co. Energiebedarf KG	Partnership interest	50.00
Westfalendamm 166, 44141 Dortmund, Germany		
DOPARK GmbH	Ordinary	25.00
Wittener Straße 45, 44789 Bochum, Germany		
CSG Convenience Service GmbH	Ordinary	24.80
Zum Ölhafen 207, 26384 Wilhelmshaven, Germany		
Nord-West Oelleitung GmbH	Ordinary	59.33
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
International airport "El. Venizelos", Athens, Greece		
SAFCO SA	Ordinary	33.33
India		
1207-1212,A2, Palladium, Nr., Orchid Wood Opp. Divyabhaskar, Corporate Rd, Makarba, Ahmedabad, India		
Blu-Smart Mobility Private Limited	Preference Series A (50.61%); Preference Series A1 (19.43%); Preference Series A2 (19.20%)	20.96
3rd Floor, Maker Chambers IV, 222, Nariman Point, Mumbai, 400 021, India		
Reliance BP Mobility Limited	Ordinary	49.00
Magenta House, Plot No. D-285, MIDC, Turbhe, Navi Mumbai, India, 400705		
Magenta EV Solutions Private Limited	Preference (53.47%)	20.89

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14. Related undertakings of the group – continued

No.10, Jawahar Road,Madurai, Tamil Nadu 625002, India, India		
Ki Mobility Solutions Private Limited	Compulsory convertible preference shares (38.10%)	3.79
One World Center, 16th Floor, Tower 2A, Senapati Bapat Marg, Mumbai, Mumbai City MH 400013, India		
Eversource Capital Private Limited	Ordinary	50.00
Unit Nos.71 & 73 7th 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. Aneka Petroindo Raya	Ordinary	49.90
PT. Dirgantara Petroindo Raya	Ordinary	49.90
Iraq		
Iraqi Airways HQ Building, Baghdad International Airport, Baghdad, Iraq		
United Iraqi Company for Airports and Ground Handling Services Limited (MASIL)	Ordinary	19.60
Naz City, Building J, Suite 10 Erbil, Iraq		
Mach Monument Aviation Fuelling Co. Ltd.	Ordinary	70.00
Ireland		
70 Northumberland Road, Ballsbridge, Dublin, D04 VH66, Ireland		
BLS Bulk Liquid Storage Cork Limited	Ordinary	30.00
Israel		
3 Shenkar Street, Herzelia, Israel		
StoreDot Ltd.	Preference Series C (21.47%); Preference Series D (14.45%)	5.07
Italy		
Via Emilia 1, 20097 San Donato Milanese, Italy		
Azule Energy Angola S.p.A	Membership Interest	50.00
Via Sardegna, Rome, 38 00187, Italy		
Air BP Italia Spa	Ordinary	50.00
Japan		
4-2 Otemachi 1-chome, Chiyoda-ku, Tokyo, Japan		
Ishikari Offshore Wind LLC	Ordinary	49.00
Yamagata Yuza Offshore Wind LLC	Ordinary	25.00
Mauritius		
3rd Floor, Standard Chartered Tower, Bank Street, 19 Cybercity, Ebene, 72201, Mauritius		
EverSource Management Holdings	Ordinary	50.00
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
Netherlands		
3196 KC Vondelingenplaat-Rt., Harbour number 3045, Butaanweg 215, Netherlands		
N.V. Rotterdam-Rijn-Pijpleiding Maatschappij (RRP)	Ordinary	44.40
Anchoragelaan 6, 1118LD Luchthaven Schiphol, Netherlands		
Gezamenlijke Tankdienst Schiphol B.V.	Ordinary	50.00
Bos en Lommerplein 280, Amsterdam, 1055RW, Netherlands		
Lightsource BP Hassan Allam Holdings B.V.	Ordinary	50.00
d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands		
Azule Energy Angola (Block 18) B.V.	Ordinary	50.00
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	25.00
Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands		
BP AOC Pumpstation Maatschap	Membership Interest	50.00
BP Esso AOC Maatschap	Partnership interest	22.80

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14. Related undertakings of the group – continued

BP Esso Pipeline Maatschap	Membership Interest	50.00
Maasvlakte Europoort Pipeline Maatschap	Partnership interest	50.00
Team Terminal B.V.	Ordinary	22.80
Strawinskylaan 1725, 1077XX Amsterdam, Netherlands		
Azule Energy Angola B.V.	Ordinary	50.00
Azule Energy Angola Production B.V.	Ordinary	50.00
Routex B.V.	Ordinary	25.00
Van Asch van Wijck 53, Amersfoort, 3811LP, Netherlands		
H2-Fifty B.V.	Ordinary	50.00
New Zealand		
149 Roscommon Road, Wiri, Puhinui 2104, New Zealand		
Wiri Oil Services Limited	Ordinary	27.78
247 Cameron Road, Tauranga, 3110, New Zealand		
McFall Fuel Limited	Ordinary	49.00
RMF Holdings Limited	Ordinary	49.00
399 Moray Place, Dunedin, 9016, New Zealand		
RD Petroleum Limited	Ordinary	49.00
Level 2, Harbour City Tower, 29 Brandon Street, Wellington Central, Wellington, 6011, New Zealand		
Glorit Solar I GP Limited	Ordinary	50.00
Glorit Solar I LP	Partnership Shares	50.00
Glorit Solar P GP Limited	Ordinary	50.00
Kowhai Park I GP Limited	Ordinary	50.00
Kowhai Park I LP	Limited Partner	50.00
Kowhai Park P GP Limited	Ordinary	50.00
Kowhai Park P LP	Limited Partner	50.00
Level 3, 139 The Terrace, Wellington, 6011, New Zealand		
New Zealand Oil Services Limited	Ordinary	50.00
Norway		
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
Trondheim Lufthavn Værnes, 7502 Stjørdal, Norway		
Flytanking AS	Ordinary	50.00
Oman		
P.O.Box 20302/211, 20302, Oman		
BP Dhofar LLC	Ordinary	49.00
PO Box 261, Postal Code 118, Sultanate of Oman, Oman		
Hyport Coordination Company LLC	Ordinary	49.00
Paraguay		
Av. España 1369 esquina San Rafael, Asunción, Paraguay		
Axion Energy Paraguay S.R.L.	Membership Interest	50.00
Peru		
Avenida Ricardo Rivera Navarrete n.501 / room 1602, Lima, Peru		
Air BP PBF del Peru S.A.C.	Ordinary	50.00
Poland		
Plac Rodta 8, PL-70-419, Szczecin, Poland, Poland		
GEWI Sp Z.O.O	Ordinary	38.20
Prinses Beatrixlaan 35, The Hague, Netherlands		
Air BP Aramco Poland sp. z o. o.	Ordinary	50.00
Portugal		
Edificio GOC, Sala SABA - Aeroporto de Lisboa, Lisboa, Portugal		
SABA- Sociedade Abastecedora de Aeronaves, Lda	Ordinary	25.00
Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal		
Charging Together, Unipessoal LDA	Ordinary	50.00
Romania		
Otopeni, 59 Aurel Vlaicu Street, Otopeni, Ilfov County, Romania		
Romanian Fuelling Services S.R.L.	Ordinary	50.00

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14. Related undertakings of the group – continued

Russian Federation		
119049, Moscow, municipal district Yakimanka, Shabolovka street 10 building 2, 7th floor, room 13, Russian Federation		
Srednelenskoye Limited Liability Company	Membership Interest	49.00
119049, Moscow, ul Shabalovka, bldg 10, corpus 2, floor 7 area XXVI, room 14., Russian Federation		
Limited Liability Company Yermak Neftegaz	Membership Interest	49.00
629830 Yamalo-Nenetskiy Anatomy Region, city of Gubkinskiy, Russian Federation		
LLC "Kharampurneftegaz"	Membership Interest	49.00
Pervomayskaya street, 32A, Sakha (Yakutiya) Republic, Lensk, 678144, Russian Federation		
Lensky Nefteprovod Limited Liability Company	Membership Interest	20.00
Limited Liability Company TYNGD	Membership Interest	20.00
Saudi Arabia		
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[d]	Ordinary	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		
Eversource II Partners Pte. Ltd	Ordinary	50.00
Green Growth Feeder Fund Pte. Ltd	Ordinary	50.00
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	37.49
135 Honshu Road, Islandview, Durban, 4052, South Africa		
Blendcor (Pty) Limited	Ordinary B	37.49
199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, GP, 2196, South Africa		
Masana Petroleum Solutions (Pty) Ltd	Ordinary	37.86
Spain		
163, Paseo de la Castellana, planta baja, Madrid, 28046, Spain		
Charging Together, S.L.	Ordinary	50.00
4, Torre Iberdrola, Plaza Euskadi 5, planta 9, Bilbao, 48009, Spain		
Pan American Energy, S.L.	Membership Interest	50.00
Southern Cone Developments, S.L.	Ordinary	50.00
Avenida de la Carrera 3, 1ª, oficina 1, Pozuelo de Alarcón, Madrid, Spain		
Guadame Renovables, A.I.E.	General Partnership Interest	20.02
Calle Américo Vespucio 5-1, planta 2, número 1, Isla de la Cartuja, 41092, Sevilla, Spain		
Guillena 400 Promotores, S.L.	Ordinary	24.55
Calle Lituania nº 10, Castellón de la Plana, Spain		
Fundación para la Eficiencia Energética de la Comunidad Valenciana	Membership Interest	33.33
Calle Pedro Teixeira, 8 (edificio Iberia Mart), 8º, 28020 Madrid, Spain		
Servicios Logísticos de Combustibles de Aviación, S.L	Ordinary	50.00
Campus Empresarial Arbea - Edificio No 1, Carretera Fuencarral a Alcobendas (M-603), km 3.8, Alcobendas, Madrid, Spain		
Hokchi Iberica, S.L.	Ordinary	50.00
L13 ENERGY INVESTMENTS S.L.	Quotas	35.00
Li3 Energy Holding, S.L.	Ordinary	35.00
PAE Desarrollos Energeticos, S.L.	Ordinary	50.00
PAE Energy Holding, S.L.	Membership Interest	50.00
Pan American Energy Group, S.L.	Ordinary B	50.00
Pan American Energy Iberica, S.L.	Ordinary	50.00
Cardenal Marcelo Spinola, 42, 28016 Madrid, Spain		
Olmedo Renovables 400 kV, A.I.E.	Membership Interest	30.24
Carretera de San Andréss/n, La Jurada-María Jiménez, Santa Cruz de Tenerife, Spain		
Terminales Canarios, S.L.	Ordinary	50.00
Paseo De La Castellana 91 4º 4 Madrid, Spain		
Gómez Narro Renovables 132 kV, A.I.E	Membership Interest	45.45

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Sweden		
Box 135, 190 46 Arlanda, Sweden		
A Flygbranslehantering AB (AFAB)	Ordinary	25.00
Box 2154, Landvetter, 438 14, Sweden		
Gothenburgh Fuelling Company AB (GFC)	Ordinary	33.33
Box 22, SE 230 32 Malmö-Sturup, Sweden		
Malmo Fuelling Services AB	Ordinary	33.33
Box 7, 190 45 Arlanda, Sweden		
Stockholm Fuelling Services Aktiebolag	Ordinary	25.00
Switzerland		
Route de Pré-Bois 17, Cointrin, 1216, Switzerland		
Saraco SA	Ordinary	20.00
Trans Adriatic Pipeline AG, Lindenstrasse 2, 6340 Baar, Switzerland		
Trans Adriatic Pipeline AG	Ordinary	20.00
Zwüscheteich, Rümlang, 8153, Switzerland		
TAR - Tankanlage Ruemlang AG	Ordinary	27.32
Thailand		
23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand		
Pacroy (Thailand) Co., Ltd.	Ordinary (100.00%); Preference (0.82%)	39.50
Trinidad and Tobago		
48-50 Sackville Street, Port of Spain, Trinidad and Tobago		
Solar Photovoltaic Holding Company of Trinidad and Tobago Limited	Ordinary	35.00
Princes Court, Cor. Pembroke & Keate Street, Port-of-Spain, Trinidad and Tobago		
Atlantic LNG 4 Company of Trinidad and Tobago Unlimited	Ordinary	37.78
Atlantic LNG Company of Trinidad and Tobago	Ordinary	47.15
Türkiye		
Degirmen yolu cad. No:28, Asia OfisPark K:3 Icerenkoy-Atasehir, Istanbul, 34752, Türkiye		
ATAS Anadolu Tasfiyehanesi Anonim Sirketi[f]	Ordinary	17.00
Söğütözü Caddesi, Koç Kuleleri B Blok Söğütözü Mahallesi 2B/37, Çankaya/Ankara, 06510, Türkiye		
TANAP Dogalgaz Iletim Anonim Sirketi	Ordinary C (100.00%)	12.00
United Arab Emirates		
Building 01, Office 01 Central Park, Masdar City, Abu Dhabi, UAE, United Arab Emirates		
The Catalyst Limited	Ordinary	50.00
Middle East Lubricants Company LLC, po box 1699, 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 261143, Dubai, United Arab Emirates		
Emoil Storage Company FZCO	Ordinary	20.00
P.O.Box 261781, Dubai, United Arab Emirates		
EMDAD Aviation Fuel Storage FZCO	Ordinary	33.33
Sharjah 42244, Sharjah, UAE,Sharjah, United Arab Emirates		
Sharjah Pipeline Company LLC	Ordinary	24.01
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		
S&JD Robertson North Air Limited	Ordinary	49.00
125, Old Broad Street, London, EC2N 1AR, England, United Kingdom		
Azule Energy Holdings Limited	Ordinary	50.00
Azule Energy Exploration (Angola) Limited	Ordinary	50.00
Azule Energy Exploration Angola (KB) Limited	Ordinary	50.00
Azule Energy Limited	Ordinary	50.00
1st Floor, 282 Earls Court Road, London, SW5 9AS, United Kingdom		
Torro Ventures Ltd.	Ordinary (18.70%); Preference Series B (39.09%)	24.00

14. Related undertakings of the group – continued

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, England, United Kingdom		
British Pipeline Agency Limited	Ordinary	50.00
United Kingdom Oil Pipelines Limited	Ordinary	22.00
Walton-Gatwick Pipeline Company Limited	Ordinary	42.33
West London Pipeline and Storage Limited	Ordinary	30.50
6th Floor, 60 Gracechurch Street, London, EC3V 0HR, United Kingdom		
Gasrec Ltd	Ordinary A (39.50%)	36.67
9 Caxton House, Broad Street, Great Cambourne, Cambridge, CB23 6JN, England, United Kingdom		
Joint Inspection Group Limited	Membership Interest	14.28
C/O ERNST & YOUNG LLP, The Paragon Counterslip, Bristol, BS1 6BX, United Kingdom		
Green Biofuels Limited	Ordinary	30.00
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		
Arcius Energy Egypt Limited	Ordinary	51.00
Arcius Energy Limited	Ordinary	51.00
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
Net Zero North Sea Storage Holdings Limited	Ordinary	45.00
Net Zero North Sea Storage Limited	Ordinary	45.00
Eni House, 10 Ebury Bridge Road, London, SW1W 8PZ, England, United Kingdom		
Solenova Limited	Membership Interest	25.00
VIC CBM Limited	Ordinary	50.00
Virginia Indonesia Co. CBM Limited	Ordinary	50.00
Johnston Carmichael, Bishop's Court, 29 Albyn Place, Aberdeen, AB10 1YL, Scotland, United Kingdom		
bp Aberdeen Hydrogen Energy Limited	Ordinary B	45.77
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%)	24.89
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, England, United Kingdom		
Blue Marble Holdings Limited (in liquidation)	Ordinary C (96.53%)	23.58
One Bartholomew Close, London, EC1A 7BL, United Kingdom		
Manchester Airport Storage and Hydrant Company Limited	Ordinary	25.00
Oxbotica Uhq 8050 Alec Issigonis Way, Oxford Business Park North, Oxford, Oxfordshire, OX4 2HW, England, United Kingdom		
Oxa Autonomy Ltd	Ordinary (1.10%); Preference Series B (17.79%); Preference Series C (22.37%)	11.26
Shell Centre, London, SE1 7NA, United Kingdom		
Shell Mex and B.P. Limited	Ordinary B	40.00
SM Realisations Limited (In Liquidation)	Membership Interest	40.00
The Consolidated Petroleum Company Limited	Ordinary B	50.00
The Consolidated Petroleum Supply Company Limited[e]	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

14. Related undertakings of the group – continued

Unit 9 Armstrong Mall, Southwood Business Park, Farnborough, GU14 0NR, England, United Kingdom		
Blue Ocean Seismic Services Limited	Preference Series A (51.28%)	31.25
Windsor House, Cornwall Road, Harrogate, England, HG1 2PW, United Kingdom		
C-Capture Limited	Preference Series A (23.17%)	18.75
United States		
1 Riverside Plaza, Columbus, OH, 43215, United States		
Auwahi Holdings, LLC	Membership Interest	50.00
108 Lakeland Avenue, Dover, Kent, DE, 19901		
Azule Energy Gas Supply Services Inc.	Ordinary	50.00
1560 Broadway, Suite 2090, Denver, Colorado, 80202, United States		
Cedar Creek II, LLC	Membership Interest	50.00
160 Greentree Drive, Suite 101, City of Dover, County of Kent, DE, 19901, 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
2140 S. Dupont Highway, Camden, County of Kent, DE, 19934, United States		
Beyond Limits, Inc.	Preference Series B (100.00%); Preference Series C (20.07%)	12.25
2710 Gateway Oaks Drive, Suite 150N Sacramento, CA, 95833-3505, United States		
East Travel Plaza LLC	Membership Interest	40.00
Petro Travel Plaza LLC	Membership Interest	40.00
2711 Centerville Road, Suite 400, Wilmington, DE, 19808, United States		
Energy Emerging Investments, LLC	Membership Interest	50.00
3410 Belle Chase Way, Suite 600, Lansing, MI, 48911, United States		
Sunshine Gas Producers, LLC	Membership Interest	60.00
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		
Auwahi Wind Energy LLC	Membership Interest	50.00
SeaPort Midstream Partners, LLC	Membership Interest	49.00
WasteFuel Global, Inc.	Series B preferred stock (99.50%)	2.63
920 North King Street, 2nd Floor, Wilmington DE 19801, United States		
Atlantic 2/3 Holdings LLC	Membership Interest	47.15
Atlantic 4 Holdings LLC	Membership Interest	37.78
c/o Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808, United States		
Apis Innovation Inc.	Ordinary	37.43
Astro Solar Construction Holdings, LLC	Membership Interest	53.22
Astro Solar Construction, LLC	Membership Interest	53.22
Astro Solar Holdings 1, LLC	Membership Interest	53.22
Astro Solar Holdings 2, LLC	Membership Interest	53.22
Astro Solar Manager, LLC	Membership Interest	53.22
Atlas RNG LLC	Membership Interest	50.00
Aurum Renewables LLC	Class B Membership Interest	60.00
Bass Solar Class B, LLC	Membership Interest	53.22
Bass Solar Construction, LLC	Membership Interest	53.22
Bass Solar Holdings 1, LLC	Membership Interest	53.22
Bass Solar Holdings 2, LLC	Membership Interest	53.22
Bass Solar Holdings, LLC	Class B Membership Interest	53.22
Bellflower Solar 1, LLC	Membership Interest	53.22
Bighorn Solar 1, LLC	Membership Interest	53.22
Bighorn Solar Class B, LLC	Membership Interest	53.22
Bighorn Solar Construction, LLC	Membership Interest	53.22
Bighorn Solar Holdings 1, LLC	Membership Interest	53.22
Bighorn Solar Holdings 2, LLC	Membership Interest	53.22

The parent company financial statements of BP p.l.c. on pages 251-310 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Bighorn Solar Holdings, LLC	Class B Membership Interest	53.22
Black Bear Alabama Solar 1, LLC	Membership Interest	27.40
Black Bear Alabama Solar Holdings 1, LLC	Membership Interest	53.22
Black Bear Alabama Solar Holdings 2, LLC	Membership Interest	53.22
Black Bear Alabama Solar Holdings, LLC	Membership Interest	27.40
Black Bear Alabama Solar Land Holdings, LLC	Membership Interest	53.22
Black Bear Alabama Solar Manager, LLC	Membership Interest	53.22
Briar Creek Solar 1, LLC	Membership Interest	53.22
Cardinal Solar Class B, LLC	Membership Interest	53.22
Cardinal Solar Construction Holdings, LLC	Membership Interest	53.22
Cardinal Solar Construction, LLC	Membership Interest	53.22
Cardinal Solar Holdings 1, LLC	Membership Interest	53.22
Cardinal Solar Holdings 2, LLC	Membership Interest	53.22
Cardinal Solar Holdings, LLC	Class B Membership Interest	53.22
CES Biogas LLC	Membership Interest	60.00
Clean Eagle RNG, LLC	Membership Interest	50.00
Continental Divide Solar I, LLC	Membership Interest	53.22
Continental Divide Solar II, LLC	Membership Interest	53.22
Continental Divide Solar Land Holdings, LLC	Membership Interest	53.22
Cottontail Solar 1, LLC	Membership Interest	53.22
Cottontail Solar 2, LLC	Membership Interest	53.22
Cottontail Solar 5, LLC	Membership Interest	53.22
Cottontail Solar 6, LLC	Membership Interest	53.22
Cottontail Solar 8, LLC	Membership Interest	53.22
Cottontail Solar Class B, LLC	Membership Interest	53.22
Cottontail Solar Construction Holdings, LLC	Membership Interest	53.22
Cottontail Solar Construction, LLC	Membership Interest	53.22
Cottontail Solar Holdings 1, LLC	Membership Interest	53.22
Cottontail Solar Holdings 2, LLC	Membership Interest	53.22
Cottontail Solar Holdings, LLC	Class B Membership Interest	53.22
Eden RNG LLC	Membership Interest	50.00
Elm Branch Solar 1, LLC	Membership Interest	53.22
Glade CD Solar Holdings, LLC	Membership Interest	53.22
Glade Solar Class B, LLC	Membership Interest	53.22
Glade Solar Construction Holdings, LLC	Membership Interest	53.22
Glade Solar Construction, LLC	Membership Interest	53.22
Glade Solar Holdings 1, LLC	Membership Interest	53.22
Glade Solar Holdings 2, LLC	Membership Interest	53.22
Glade Solar Holdings, LLC	Class B Membership Interest	53.22
Glade Solar Land Holdings, LLC	Membership Interest	53.22
Green Meadows RNG LLC	Membership Interest	50.00
Honeysuckle Solar, LLC	Membership Interest	53.22
Impact Solar 1, LLC	Membership Interest	53.22
Impact Solar Class B, LLC	Membership Interest	53.22
Impact Solar Construction, LLC	Membership Interest	53.22
Impact Solar Holdings 1, LLC	Membership Interest	53.22
Impact Solar Holdings 2, LLC	Membership Interest	53.22
Impact Solar Holdings, LLC	Class B Membership Interest	53.22
IoTecha Corp	Series C preferred stock (52.73%)	14.15
Janus RNG LLC	Membership Interest	50.00
Johnson Corner Solar I, LLC	Membership Interest	53.22
Maverick Solar Class B, LLC	Membership Interest	53.22
Maverick Solar Construction, LLC	Membership Interest	53.22
Maverick Solar Holdings 1, LLC	Membership Interest	53.22

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14. Related undertakings of the group – continued

Maverick Solar Holdings 2, LLC	Membership Interest	53.22
Maverick Solar Holdings, LLC	Class B Membership Interest	53.22
Pan RNG LLC	Membership Interest	50.00
Petro Travel Plaza Holdings LLC	Membership Interest	40.00
Prairie Ronde Solar Class B, LLC	Membership Interest	53.22
Prairie Ronde Solar Farm, LLC	Membership Interest	53.22
Prairie Ronde Solar Holdings, LLC	Class B Membership Interest	53.22
Saturn Renewables LLC	Partnership interest	50.00
Sun Mountain Solar 1, LLC	Membership Interest	53.22
Theta Solar US Holdings, LLC	Membership Interest	53.22
Titan Partners LLC	Membership Interest	25.00
UGID Broad Mountain, LLC	Membership Interest	60.00
Viridos, Inc.	Series A preferred stock (33.37%); Junior preferred stock (12.16%); Ordinary A (11.54%)	6.79
Whitetail Solar 1, LLC	Membership Interest	53.22
Whitetail Solar 2, LLC	Membership Interest	53.22
Whitetail Solar 3, LLC	Membership Interest	53.22
Whitetail Solar Land Holdings, LLC	Membership Interest	53.22
Wildflower Solar I, LLC	Membership Interest	53.22
Wildflower Solar Land Holdings, LLC	Membership Interest	53.22
Corporation Trust Center, 1209 Orange Street, Wilmington, DE, 19801, United States		
Advanced Ionics, Inc.	Series A-1 (40.91%)	13.99
Ash Grove Renewable Energy, LLC	Membership Interest	47.50
BP Gulf of Mexico Midstream Holding LLC	Membership Interest	51.00
Bridge To Renewables, Inc.	Series A preferred stock (36.36%)	25.33
Caesar Oil Pipeline Company, LLC	Membership Interest	28.56
Calysta, Inc.	Preference Series D-1	36.36
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	27.03
Drumgoon Digester Renewable Energy, LLC	Membership Interest	40.00
East Valley Development, LLC	Membership Interest	50.00
Endymion Oil Pipeline Company, LLC	Membership Interest	33.15
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
HPP SD Holdings, LLC	Membership Interest	20.70
KM Phoenix Holdings LLC	Membership Interest	25.00
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
Midwest Alliance For Clean Hydrogen, LLC	Membership Interest	26.20
Olympic Pipe Line Company LLC	Membership Interest	35.70
Pan American Energy US LLC	Membership Interest	51.00
PartsTech, Inc.	Preference Series A (65.15%); Preference Series B (17.84%)	40.13
Proteus Oil Pipeline Company, LLC	Membership Interest	33.15
Tri-Cross Renewable Energy, LLC	Membership Interest	47.50
Ursa Major Marine Holdings, LLC	Membership Interest	33.33
Van Winkle Digester Renewable Energy, LLC	Membership Interest	47.50

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14. Related undertakings of the group – continued

VF Renewable Energy, LLC	Membership Interest	40.00
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
La Cumparsita 1373, piso 4°, Montevideo, Uruguay		
Dinarel S.A.	Ordinary	20.00
Luis A de Herrera 1248, Torre II, Piso 22 (Edificio World Trade Center), Montevideo, Uruguay		
Axion Comercializacion De Combustibles Y Lubricantes S.A.	Ordinary	50.00
Zimbabwe		
Block 1 Tendeseka Office Park, Samora Machel Av/Renfrew Road, Harare, Zimbabwe		
Central African Petroleum Refineries (Pvt) Ltd	Membership Interest	20.75

a 1% interest held directly by BP p.l.c.
b 0.01% interest held directly by BP p.l.c.
c 100% interest held directly by BP p.l.c.
d 50% interest held directly by BP p.l.c.
e 5% interest held directly by BP p.l.c.

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Additional disclosures

Additional information

Capital expenditure★

			$ million
	2024	2023	2022
Capital expenditure			
Organic capital expenditure★	**16,135**	14,998	12,470
Inorganic capital expenditure[abc]★	**102**	1,255	3,860
	16,237	16,253	16,330
Capital expenditure by segment			
gas & low carbon energy[a]	**5,211**	4,281	4,251
oil production & operations	**6,198**	6,278	5,278
customers & products[abc]	**4,420**	5,253	6,252
other businesses & corporate	**408**	441	549
	16,237	16,253	16,330
Capital expenditure by geographical area			
US	**6,566**	8,105	8,656
Non-US	**9,671**	8,148	7,674
	16,237	16,253	16,330

a 2024 includes the cash acquired net of acquisition payments on completion of the bp Bunge Bioenergia and Lightsource bp acquisitions.
b 2023 includes $1.1 billion in respect of the TravelCenters of America acquisition.
c 2022 includes $3,030 million in respect of the Archaea Energy acquisition.

Adjusting items

Adjusting items are items that bp discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers to be important to period-on-period analysis of the group's results and are disclosed in order to enable investors to better understand and evaluate the group's reported financial performance. An analysis of adjusting items is shown in the table below.

			$ million
	2024	2023	2022
gas & low carbon energy			
Gain on sale of businesses and fixed assets[a]	**297**	19	45
Net impairment and losses on sale of businesses and fixed assets[a]	**(3,004)**	(2,221)	588
Environmental and related provisions	**—**	—	—
Restructuring, integration and rationalization costs[b]	**(25)**	—	8
Fair value accounting effects[cd] ★	**(1,550)**	8,859	(1,811)
Other[e]	**1,048**	(1,299)	(197)
	(3,234)	5,358	(1,367)
oil production & operations			
Gain on sale of businesses and fixed assets[a]	**144**	297	3,446
Net impairment and losses on sale of businesses and fixed assets[a]	**(790)**	(1,819)	(4,508)
Environmental and related provisions[f]	**5**	54	518
Restructuring, integration and rationalization costs[b]	**(15)**	(1)	(11)
Fair value accounting effects	**—**	—	—
Other[g]	**(492)**	(121)	52
	(1,148)	(1,590)	(503)
customers & products			
Gain on sale of businesses and fixed assets[a]	**190**	44	374
Net impairment and losses on sale of businesses and fixed assets[ah]	**(3,117)**	(1,757)	(1,983)
Environmental and related provisions	**(99)**	(97)	(101)
Restructuring, integration and rationalization costs[b]	**(123)**	—	18
Fair value accounting effects[d]	**(81)**	(86)	(309)
Other[i]	**(847)**	(287)	81
	(4,077)	(2,183)	(1,920)
other businesses & corporate			
Gain on sale of businesses and fixed assets[a]	**39**	1	1
Net impairment and losses on sale of businesses and fixed assets[a]	**(19)**	(41)	(17)
Environmental and related provisions[j]	**(87)**	(604)	(92)
Restructuring, integration and rationalization costs[b]	**(59)**	38	19
Fair value accounting effects[d]	**(221)**	630	(1,381)
Rosneft[k]	**—**	—	(24,033)
Gulf of America oil spill	**(51)**	(57)	(84)
Other	**18**	(4)	21
	(380)	(37)	(25,566)
Total before interest and taxation	**(8,839)**	1,548	(29,356)
Finance costs[l]	**(505)**	(405)	(425)
Total before taxation	**(9,344)**	1,143	(29,781)
Taxation on adjusting items[m]	**1,495**	972	456
Taxation – tax rate change effect[n]	**(316)**	232	(1,834)
Total after taxation[o]	**(8,165)**	2,347	(31,159)

a See Financial statements – Note 4 for further information.
b Restructuring charges are classified as adjusting items where they relate to an announced major group restructuring. A major group restructuring is a restructuring programme affecting more than one of the group's operating segments that is expected to result in charges of more than $1 billion over a defined period. 2024 includes charges for provisions arising from the groups transformation project that was announced on 16 January 2024. 2022 includes release of provisions for the reinvent bp restructuring costs.
c Under IFRS bp marks-to-market the value of the hedges used to risk-manage LNG contracts, but not the contracts themselves, resulting in a mismatch in accounting treatment. The fair value accounting effect includes the change in value of LNG contracts that are being risk-managed, and the underlying result reflects how bp risk-manages its LNG contracts.
d For further information, including the nature of fair value accounting effects reported in each segment, see page 355.
e 2024 includes a $508 million gain relating to the remeasurement of bp's pre-existing 49.97% interest in Lightsource bp, and $498 million relating to the remeasurement of certain US assets excluded from the Lightsource bp acquisition (see Note 3 for further information). 2023 includes $1,140 million of impairment charges recognized through equity-accounted earnings relating to our US offshore wind projects.
f 2022 includes a provision reversal relating to the change in discount rate on retained decommissioning provisions.
g 2024 includes $429 million of impairment charges recognized through equity-accounted earnings relating to our interest in Pan American Energy Group.
h For 2024, see Financial statements – Note 2 for further information.
i 2024 includes recognition of onerous contract provisions related to the Gelsenkirchen refinery. The unwind of these provisions will be reported as an adjusting item as the contractual obligations are settled.
j 2023 primarily relates to charges related to the control, abatement, clean-up or elimination of environmental pollution and legal settlements. 2022 primarily reflects charges due to the annual update of environmental provisions, including asbestos-related provisions for past operations, together with updates of non-Gulf of America oil spill related legal provisions.
k For more information see Financial statements – Note 1 Significant accounting policies, judgements, estimates and assumptions – Investment in Rosneft, and Note 17 – Investments in associates.
l All periods presented include the unwinding of discounting effects relating to Gulf of America oil spill payables and the income statement impact of temporary valuation differences related to the group's interest rate and foreign currency exchange risk management associated with finance debt. 2024 includes the unwinding of discounting effects relating to certain onerous contract provisions. 2023 and 2022 include the income statement impact associated with the buyback of finance debt.
m Includes certain foreign exchange effects on tax as adjusting items. These amounts represent the impact of: (i) foreign exchange on deferred tax balances arising from the conversion of local currency tax base amounts into functional currency; and (ii) taxable gains and losses from the retranslation of US dollar-denominated intra-group loans to local currency.
n 2024 and 2023 include revisions to the deferred tax impact of the introduction of the UK Energy Profits Levy (EPL) on temporary differences existing at 31 December 2022 that are expected to unwind before 31 March 2028. 2022 includes the deferred tax impact of the introduction of the EPL. The EPL increases the headline rate of tax to 78% (75% until 31 October 2024) and applies to taxable profits

★ See glossary on **page 351**

from bp's North Sea business made from 1 January 2023 until 31 March 2028. In October 2024 the UK government announced changes to the EPL including a 3% increase in the rate from 1 November 2024, the removal of the Levy's main investment allowance and an extension to 31 March 2030. The changes to the rate and to the investment allowance were substantively enacted in 2024. The extension of the Levy to 31 March 2030 was substantively enacted after 31 December 2024 and will result in a non-cash deferred tax charge of around $0.5 billion in the year ended 31 December 2025.

o 2023 and 2022 include a $146-million charge and a $505-million charge respectively for the EU Solidarity Contribution.

Non-IFRS information on fair value accounting effects

The impacts of fair value accounting effects, relative to management's internal measure of performance, are set out below. Further information on fair value accounting effects is provided on page 355.

			$ million
	2024	2023	2022
gas & low carbon energy			
Unrecognized (gains) losses brought forward from previous period	**(1,125)**	(9,960)	(8,149)
Favourable (adverse) impact relative to management's measure of performance	**(1,550)**	8,859	(1,811)
Exchange translation gains (losses) on fair value accounting effects	**1**	(24)	–
Unrecognized (gains) losses carried forward	**(2,674)**	(1,125)	(9,960)
customers & products			
Unrecognized (gains) losses brought forward from previous period	**(17)**	79	391
Favourable (adverse) impact relative to management's measure of performance	**(81)**	(86)	(309)
Exchange translation gains (losses) on fair value accounting effects	**2**	(10)	(3)
Unrecognized (gains) losses carried forward	**(96)**	(17)	79
other businesses & corporate			
Unrecognized (gains) losses brought forward from previous period	**(925)**	(1,555)	(174)
Favourable (adverse) impact relative to management's measure of performance[a]	**(221)**	630	(1,381)
Unrecognized (gains) losses carried forward	**(1,146)**	(925)	(1,555)
Group			
Unrecognized (gains) losses brought forward from previous period	**(2,067)**	(11,436)	(7,932)
Favourable (adverse) impact relative to management's measure of performance	**(1,852)**	9,403	(3,501)
Exchange translation gains (losses) on fair value accounting effects	**3**	(34)	(3)
Unrecognized (gains) losses carried forward	**(3,916)**	(2,067)	(11,436)
Favourable (adverse) impact relative to management's measure of performance – by region			
gas & low carbon energy			
US	**(582)**	900	(1,140)
Non-US	**(968)**	7,959	(671)
	(1,550)	8,859	(1,811)
customers & products			
US	**(214)**	(18)	3
Non-US	**133**	(68)	(312)
	(81)	(86)	(309)
other businesses & corporate			
US	**–**	–	–
Non-US	**(221)**	630	(1,381)
	(221)	630	(1,381)
	(1,852)	9,403	(3,501)
Taxation credit (charge)	**325**	(915)	434
	(1,527)	8,488	(3,067)

a Includes changes in the fair value of derivatives entered into by the group to manage currency exposure and interest rate risks relating to hybrid bonds to their respective first call periods. For further information see page 355.

Net debt including leases

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

At 31 December	2024	2023
		$ million
Net debt[a]★	**22,997**	20,912
Lease liabilities	**12,000**	11,121
Net partner (receivable) payable for leases entered into on behalf of joint operations★	**(88)**	(131)
Net debt including leases	**34,909**	31,902
Total equity	**78,318**	85,493
Gearing including leases★	**30.8%**	27.2%

a See Financial statements – Note 27 for a reconciliation of net debt to finance debt, which is the nearest equivalent measure to net debt on an IFRS basis.

Liquidity and capital resources

Financial framework

The financial framework sets out how we allocate capital, balancing between strengthening the balance sheet, investing in the business, and delivering resilient distributions.

Net debt★ at 31 December 2024 was $23.0 billion and is expected to reduce over time to a targeted range of $14-18 billion by the end of 2027, reflecting the allocation of potential proceeds from any transactions related to the Castrol strategic review and announcement to bring a strategic partner into Lightsource bp. The exact timing of achieving our net debt target range will therefore be impacted by the timing of any potential transactions. bp is committed to maintaining a strong balance sheet and 'A' range credit metrics throughout the cycle.

Our shareholder distributions include a dividend, resilient to a lower price environment, and we remain committed to sharing excess cash through share buybacks over time. Our distribution policy reflects the balance between the uses of cash alongside an ongoing consideration of factors, including changes in the environment, the underlying performance of the business, the outlook for the group financial framework, and other market factors which may vary quarter to quarter.

We expect operating cash flow to cover capital expenditure★ and the dividend. Capital expenditure in 2024 was $16.2 billion, including $0.1 billion of inorganic capital expenditure★. We expect capital expenditure of around $15 billion in 2025 and a range of $13-15 billion per annum from 2026 to 2027 including inorganic expenditure. This is a level that maximizes cash generation and grows the financial scale of the company. Within this frame we are reallocating capital to our highest returning opportunities, with an average $10 billion per year allocated to oil and gas, $3-4 billion in customers and products and less than $800 million per year in low carbon energy to 2027. In a period of low prices, the group has the flexibility to reduce or defer capital investment, as appropriate.

In 2024, the return on average capital employed★ was 14.2%[a] at an average of $81 per barrel. The return on average capital employed is targeted to be over 16% by 2027 at $70 per barrel in 2024 real terms, and assuming bp planning assumptions, as we execute our reset strategy. This is supported by an expected compound annual growth rate in adjusted free cash flow★ of over 20% from 2024 to 2027 and subject to the same price and planning assumptions.

a Nearest equivalent IFRS measures of numerator and denominator are profit for the year attributable to bp shareholders and total equity respectively: Profit for the year attributable to bp shareholders divided by total equity at the end of 2024 0.5%.

Dividends and other distributions to shareholders

The dividend is determined in US dollars, the economic currency of bp, and the dividend level is reviewed by the board each quarter. The quarterly dividend was increased from 7.270 to 8.000 cents per ordinary share per quarter in the second quarter of 2024.

The total dividend distributed to bp shareholders in 2024 was $5.0 billion (2023 $4.8 billion). This dividend was all paid in cash as shareholders no longer have the option to receive a scrip dividend in place of receiving cash.

Our dividend is resilient to a lower price environment. Based on our current forecasts and subject to the board's discretion each quarter, we expect an annual increase in the dividend per ordinary share of at least 4%.

Additionally, subject to board discretion, it is our intention to share excess cash with investors through share buybacks over time. This policy enables bp to share upside when the price environment is stronger, while ensuring the balance sheet remains resilient in a lower price environment. Taken together, our guidance is for total dividends and share buybacks to be in the range of 30 to 40% of operating cash flow over time, including buybacks to offset dilution from employee share schemes.

In 2024 bp executed $7.1 billion of share buybacks (2023 $7.9 billion), including fees and stamp duty. Since 1 January 2025 an additional $927 million shares have been repurchased up to 14 February 2025, including fees and stamp duty.

In setting the dividend and share buybacks each quarter, the board will continue to take into account factors including the cumulative level of and outlook for cash flow, share count reduction from buybacks and maintaining 'A' range credit metrics.

Financing the group's activities

The group's principal commodities, oil and gas, are priced internationally in US dollars. Group policy has generally been to minimize economic exposure to currency movements by financing operations with US dollar debt. Where debt and hybrid bonds are issued in other currencies, they are generally swapped back to US dollars using derivative contracts, or else hedged by maintaining offsetting cash positions in the same currency. Cash balances of the group are mainly held in US dollars or swapped to US dollars, and holdings are well diversified to reduce concentration risk. The group is not, therefore, exposed to significant currency risk regarding its cash or borrowings. Also see Risk factors on page 65 for further information on risks associated with prices and markets, and Financial statements – Note 29.

The group's finance debt at 31 December 2024 amounted to $59.5 billion (2023 $52.0 billion). Of the total finance debt, $4.5 billion is classified as short term at the end of 2024 (2023 $3.3 billion). See Financial statements – Note 26 for more information on the short-term balance. Net debt★ was $23.0 billion at the end of 2024, an increase of $2.1 billion from the 2023 year-end position of $20.9 billion. BP p.l.c. fully and unconditionally guarantees securities issued by BP Capital Markets p.l.c. and BP Capital Markets America Inc., which are 100%-owned finance subsidiaries of BP p.l.c.

At 31 December 2024 the group held a balance of $16.6 billion (2023 $13.6 billion) issued perpetual subordinated hybrid instruments consisting of $14.6 billion (2023 $12.1 billion) hybrid bonds and $2.0 billion (2023 $1.5 billion) hybrid securities. Proceeds from hybrid securities are typically earmarked to fund specific project or investment activities. As the group has the unconditional right to avoid transfer of cash or another financial asset in relation to these hybrid instruments, which were issued by group subsidiaries, they are classified as equity instruments and reported within non-controlling interest.

The ratio of finance debt to finance debt plus total equity at 31 December 2024 was 43.2% (2023 37.8%). Gearing was 22.7% at the end of 2024 (2023 19.7%). See Financial statements – Note 27 for finance debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt.

Cash and cash equivalents of $39.2 billion at 31 December 2024 (2023 $33.0 billion) are included in net debt. We manage our cash position so that the group has adequate cover to respond to potential short-term market liquidity, short-term price environment volatility, and expect to maintain a robust cash position.

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

We believe that the group's resilient balance sheet and strong investment grade credit rating will allow the group to meet its known contractual and other obligations in both the short and long term with the group having sufficient working capital, taking into account the amounts of undrawn borrowing facilities, access to capital markets, levels of cash and cash equivalents and its ongoing ability to generate cash through operations. This belief is subject to a degree of uncertainty that can be expected to increase looking out over time and, accordingly, that future outcomes cannot be guaranteed or predicted with certainty.

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

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

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

The information above contains forward-looking statements, which by their nature involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of bp. You are urged to read the Cautionary statement on page 338 and Risk factors on page 65, which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Off-balance sheet arrangements

At 31 December 2024, the group's share of third-party finance debt and lease liabilities of equity-accounted entities was $8.0 billion (2023 $9.9 billion). These amounts are not reflected in the group's debt on the balance sheet. The group has issued third-party guarantees under which amounts outstanding, incremental to amounts recognized on the balance sheet at 31 December 2024, were $655 million (2023 $1,655 million) in respect of liabilities of joint ventures★ and associates★ and $585 million (2023 $598 million) in respect of liabilities of other third parties. Of these amounts, $655 million (2023 $1,609 million) of the joint ventures and associates guarantees relate to borrowings and, for other third-party guarantees, $430 million (2023 $527 million) relate to guarantees of borrowings.

Contractual obligations

The following table summarizes the group's capital expenditure commitments for property, plant and equipment at 31 December 2024 and the proportion of that expenditure for which contracts have been placed.

			$ million
			Payments due by period
Capital expenditure	Less than 1 year	More than 1 year	Total
Committed	12,520	13,513	26,033
of which is contracted	7,649	5,993	13,642

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

In addition, at 31 December 2024 the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $3,976 million. Contracts were in place for $3,451 million of this total.

The following table summarizes the group's principal contractual obligations at 31 December 2024, distinguishing between those for which a liability is recognized on the balance sheet and those for which no liability is recognized. See Financial framework above for bp's approach to capital allocation and Financing the group's activities above for bp's plan and ability to generate and obtain cash in the short and long term. Also see Financial statements – Note 23 for more information on provisions, Note 24 on pensions and other post-employment benefits, Note 26 on borrowings, Note 28 on leases, Note 29 and Note 30 on derivatives and financial instruments.

			$ million
			Payments due by period
Expected payments by period under contractual obligations	Less than 1 year	More than 1 year	Total
Balance sheet obligations			
Borrowings[a]	6,892	70,354	77,246
Lease liabilities[b]	3,237	11,031	14,268
Decommissioning liabilities[c]	643	23,967	24,610
Environmental liabilities[c]	349	1,584	1,933
Gulf of America oil spill liabilities[d]	1,137	8,383	9,520
Pensions and other post-employment benefits[e]	533	13,403	13,936
	12,791	128,722	141,513
Off-balance sheet obligations			
Unconditional purchase obligations[f]			
Crude oil and oil products	61,541	7,094	68,635
Natural gas and LNG	15,350	54,579	69,929
Chemicals and other refinery feedstocks	1,011	1,509	2,520
Power	6,111	14,165	20,276
Utilities	54	393	447
Transportation	2,000	14,538	16,538
Use of facilities and services	3,189	23,918	27,107
	89,256	116,196	205,452
Total	102,047	244,918	346,965

a Expected payments include interest totalling $20,854 million (less than 1 year $2,490 million, more than 1 year $18,364 million).
b Expected payments include interest totalling $2,268 million (less than 1 year $460 million, more than 1 year $1,808 million).
c The amounts presented are undiscounted.
d The amounts presented are undiscounted. Gulf of America oil spill liabilities are included in the group balance sheet, on a discounted basis, within other payables. See Financial statements – Note 22 for further information.
e Represents the expected future contributions to funded pension plans and payments by the group for unfunded pension plans, and the expected future payments for other post-employment benefits.
f Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms (such as fixed or minimum purchase volumes, timing of purchase and pricing provisions). Agreements that do not specify all significant terms, or that are not enforceable, are excluded. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2025 include purchase commitments existing at 31 December 2024 entered into principally to meet the group's short-term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Financial statements – Note 29.

Commitments for the delivery of oil and gas

We sell crude oil, natural gas and liquefied natural gas under a variety of contractual obligations. Some of these contracts specify the delivery of fixed and determinable quantities. For the period from 2025 to 2027 worldwide, we are contractually committed to deliver approximately 444 million barrels of oil, 6,277 billion cubic feet of natural gas, and 70Mt of liquefied natural gas. The commitments principally relate to group subsidiaries★ based in Azerbaijan, Oman, Trinidad and Tobago, the UK and the US. We expect to fulfil these delivery commitments with production from our proved developed reserves and supplies from existing contracts, supplemented by market purchases as necessary.

Oil and gas disclosures for the group

Analysis by region

Our oil and gas operations are set out below by geographical area, with associated significant events for 2024. bp's percentage working interest in oil and gas assets is shown in brackets. Working interest is the cost-bearing ownership share of an oil or gas lease. Consequently, the percentages disclosed for certain agreements do not necessarily reflect the percentage interests in proved reserves, production or revenue.

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

Our upstream LNG activities are located in Abu Dhabi, Angola, Australia, Indonesia, Trinidad and from 2025, in Mauritania and Senegal. In 2024 our production was 11Mt of LNG from these assets, of which 4Mt were marketed through supply, trading and shipping (ST&S) , which supplements equity production with merchant third party volumes, leading to a global long-term strategic LNG portfolio of 23Mttpa. In addition to the long-term equity and merchant supply portfolio, bp has delivered 14Mtpa in 2024 of incremental merchant volumes through short and mid-term cargos managed through the ST&S LNG business. These supplement the long-term portfolio and allow generation of short-term value when opportunities exist.

The LNG is marketed through contractual rights to access import terminal capacity into the liquid gas markets of Europe, and the UK, and relationships to market directly to end-user customers or trading entities. LNG is supplied to all major LNG demand centres, for example Argentina, Brazil, the Caribbean, China, Croatia, the Mediterranean, Iberia and north-west Europe, India, Japan, Singapore, South Korea, Taiwan, Thailand, Türkiye and the UK.

Europe

bp has interest in offshore oil and gas activities in the UK and Norway. In 2024 bp's UK production came from two key areas: the Shetland area comprising the Clair and Schiehallion fields; and the central area comprising the Andrew area, Culzean, Vorlich and ETAP fields. In Norway, production was through our equity-accounted 15.9% interest in Aker BP.

- On 10 May bp was awarded a licence for two blocks in the central North Sea, consolidating our position around our Eastern Trough Area Project (ETAP) central processing facility. The award aligns with our strategic focus on oil and gas opportunities that can be developed through established production facilities.
- On 3 September Aker BP announced oil production had started from the Tyrving field in the Alvheim area (bp 15.9%). Tyrving is operated by Aker BP (61.26% working interest). The Tyrving development is part of the life extension of the Alvheim field and is expected to increase production while reducing both unit costs and emissions. Recoverable resources in Tyrving are approximately 25 million barrels of oil equivalent (gross).
- On 14 January 2025 Aker BP was awarded interests in 19 licences (of which it will operate 16) in the North Sea and Norwegian Sea (bp 15.9%).
- During the year an impairment charge of $1 billion was recognized in respect of certain assets in the North Sea as a result of changes to reserves and tax assumptions.

North America

Our oil and gas activities in North America are located in four areas: deepwater Gulf of America, the Lower 48 states, Canada and Mexico.

bp has around 280 lease blocks in the Gulf of America and operates five production hubs.

- On 9 February the final investment decision was taken on the Atlantis Drill Center Expansion, which will be a two well tieback to the Atlantis facility in the Gulf of America (bp share 56%).
- On 30 July bp made the final investment decision on the Kaskida project in the deepwater Gulf of America. Kaskida will be bp's sixth hub in the Gulf of America and is expected to have a production capacity of 80,000 barrels of crude oil per day (bp 100%). Following this decision, bp entered into agreements with Enbridge Offshore Facilities LLC to construct, own and operate oil and gas export pipelines to transport oil from Kaskida to the Green Canyon 19 platform and gas to markets in Louisiana. bp also entered into agreements with Shell Pipeline Company LP to transport oil from Green Canyon 19 to markets in Louisiana via a new build pipeline.

bpx energy, bp's onshore oil and gas business in the Lower 48 states, has significant operated and non-operated activities across Louisiana and Texas producing natural gas, oil, NGLs and condensate, with primary focus on developing unconventional resources. It had a 1.5 billion boe proved reserve base at 31 December 2024, predominantly in unconventional reservoirs (tight gas★, shale gas and shale oil). bpx energy's core assets span 0.8 million net developed acres with nearly 1,600 operated gross wells at 31 December 2024. Daily net production averaged 434mboe/d in 2024.

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

- In April bpx energy successfully brought online 'Checkmate', its third central processing facility in the Permian Basin. It is a low-emission, electrified facility that will enable further production growth for bpx energy in the basin (bp 100% operator).

bp's onshore US crude oil and product pipelines and related transportation assets were included in the customers & products segment in 2024.

In Canada, bp is focused on pursuing offshore exploration and development opportunities and conducts trading and marketing activities across various energy commodities. We hold exploration and significant discovery licences in offshore Newfoundland and Labrador, including an interest in the Equinor-operated Bay du Nord project. bp also holds offshore exploration licences in the Arctic, where the moratorium has been extended until 31 December 2028.

In Mexico, bp held interests in an exploration block in the Salina Basin with Equinor and Total, Block 1 (bp 33% operator) and an exploration block in the Sureste Basin, Block 34 (bp 42.5% operator), with Total, QPI Mexico and Hokchi Energy. Hokchi Energy is a subsidiary of Pan American Energy Group (PAEG, see below) in which bp owns 50%. Separate to the above holdings in Mexico, Hokchi Energy also holds an interest in two other blocks.

- Formal relinquishment of Block 1 and Block 34 licences is still pending regulatory approval.

South America

bp has oil and gas activities in Argentina, Brazil and Trinidad and Tobago and, through PAEG, in Argentina and Bolivia.

In Argentina, the bp and Total (operator) partnership on a 50:50 basis in two offshore exploration concessions has been relinquished as per regulatory approval received on 11 July.

In Brazil bp has interests in eight exploration areas across three basins:

- In April the appraisal plan for Alto de Cabo Frio Central block (bp 50%), in the southern portion of the Campos Basin, was approved by the regulator.
- In May the Production Sharing Contract for the Tupinamba block, awarded to bp in 2023 during Brazil´s second Permanent Production Sharing Offer bid round was executed. bp holds 100% participation interest.
- In November bp, as operator in the BAR-M-346 block (bp 50%) filed a request to the regulatory authorities for exemption from the unfulfilled Minimum Work Program and Contract Termination due to delays in the environmental licensing process and is pending approval.

PAEG, a joint venture that is owned by bp (50%) and BC E&P Uruguay S.A. (50%), has activities mainly in Argentina and as noted above Mexico, and is also present in Bolivia.

In Trinidad and Tobago bp holds interests in exploration and production licences and production-sharing contracts (PSCs)★ covering 2.8 million acres offshore of the east and north-east coast. Facilities include 12 offshore platforms, 2 subsea tiebacks and 2 onshore processing facilities. Production comprises gas and associated liquids.

bp also holds interests in the Atlantic LNG facility. The total gross capacity of the LNG trains 2, 3 and 4 is approximately 12Mtpa.

The Atlantic Train 1 plant has not been operational since 2020. The Atlantic shareholders, bp, Shell and the National Gas Company of Trinidad & Tobago (NGC), agreed to decouple the Train from the rest of the Atlantic facility with a view to decommissioning it. The Train has been made safe and decoupling and decommissioning work scopes are being planned. In 2023 bp, Shell and NGC agreed to and executed the agreements for the restructuring of the ownership and commercial framework of the Atlantic LNG facility. The new ownership and commercial structure have been agreed for Trains 2 and 3 and took effect from 1 October 2024. Train 4 (T4) contracts expire on 1 May 2027, at which time, T4 will be rolled into the restructured arrangement. bp's shareholding averages 43% across the two companies which own the LNG trains comprising the LNG facility.

- On 24 July bp and its partner the National Gas Company of Trinidad and Tobago Limited were awarded an exploration and production licence by the Bolivarian Republic of Venezuela for the development of the Cocuina gas discovery. Cocuina is the Venezuelan portion of the cross-border Manakin-Cocuina gas field. bp is operator of the Manakin block which was discovered in 1998. Manakin declared commerciality in January 2018; however, cross-border discussions had not progressed due to the impact of US sanctions. In October 2023 the US government eased sanctions on Venezuela's oil sector for six months and further extended for two years until May 2026. The seismic acquisition programme over the joint Manakin-Cocuina field was successfully completed during September 2024.
- On 14 August bp announced it had agreed with EOG Resources Trinidad Limited (EOG) to partner on the Coconut gas development. bp approved the final investment decision for the project in June. Coconut is a 50/50 joint venture with EOG as operator. The first gas is expected in 2027.
- On 2 September bp announced it has entered into an agreement with Perenco T&T to sell four mature offshore gas fields and associated production facilities in Trinidad & Tobago (Immortelle, Flamboyant, Amherstia and Cashima). The deal also included undeveloped resources from the Parang area and completed in December 2024.
- On 19 November bp entered into a Production Sharing Contract (PSC) with the Government of the Republic of Trinidad and Tobago for Block NCMA 2, located approximately 30 miles off Trinidad's north coast. Seismic reprocessing activity is planned during 2025.
- Cypre, bp's third subsea gas development in Trinidad and Tobago, started drilling in 2024 with first gas expected in 2025. The project is expected to have seven wells and be tied back to the Juniper platform.
- In September construction of the Ocelot project, which is a 6-inch liquids pipeline connecting Beachfield to terminal operations at Galeota Point, was completed.
- The Mento (bp 50%/EOG 50% and operator) platform has sailed away, and installation was completed before the end of 2024. First gas is expected in the second quarter of 2025.

Africa

bp's oil and gas activities in Africa are located in Angola, Egypt, Libya, Mauritania and Senegal.

In Angola, bp and Eni each own a 50% interest in the Azule Energy joint venture. Azule Energy is Angola's largest independent equity producer of oil and gas, holding stakes in 18 licences, as well as an interest in the Angola LNG plant.

- In December Azule Energy completed acquisition of a 42.5% interest in exploration block 2914A (PEL85), Orange Basin, offshore Namibia.
- Azule Energy Finance Plc, a financing vehicle of Azule Energy Holdings Limited, has issued unsecured notes in an aggregate principal amount of $1,200 million. The notes have a term of 5 years and a coupon of 8.125% per annum.

In Egypt, bp holds an investment in West Nile Delta. Through its joint ventures with Egyptian Natural Gas Holding Company (EGAS), Egyptian General Petroleum Corporation (EGPC), International Egyptian Oil Company (IEOC), Eni, the Pharaonic Petroleum Company (PhPC), ADNOC, and through collaboration with Belayim Petroleum Company (Petrobel), bp and its partners now produce more than 60% of Egypt's total gas supply. In addition, bp owns interest in other exploration projects.

- On 14 February bp and ADNOC announced the formation of a new joint venture in Egypt. In December bp completed the contribution of the North Damietta and Shorouk concessions, containing the producing Atoll and Zohr fields, and three exploration concessions in Egypt to the newly created joint venture Arcius Energy Limited (bp 51%, XRG 49%).

In Libya, bp partners with the Libyan Investment Authority (LIA) and Eni (operator) in an exploration and production-sharing agreement (EPSA) to explore acreage in the onshore Ghadames and offshore Sirt basins (bp 42.5%).

- Exploration operations under the EPSA resumed in 2023, following the period of force majeure between 2012 and 2022. On 26 October drilling commenced for the first exploration well in the Onshore Ghadames basin.

In Mauritania and Senegal, bp retains the exploitation licences in the respective C8 and Saint Louis Offshore Profond blocks pertinent to the Greater Tortue Ahmeyim (GTA) Unit cross-border development.

- On 29 April the BirAllah gas resource exploration licence in which bp held a 62% participating interest expired in accordance with the terms of the applicable Production Sharing Contract, following the end of sub-phase 2.
- On 2 January 2025 bp announced that first gas had begun flowing from the GTA wells on 31 December 2024.
- In 2024 an impairment charge of $1.5 billion was recognized in respect of certain assets in the region due to increased future forecast expenditure.

Asia

bp has activities in Abu Dhabi, Azerbaijan, China, India, Indonesia, Iraq, Kuwait and Oman.

In China, we have a 30% equity stake in the Guangdong LNG regasification terminal and trunkline project (GDLNG) with a total storage capacity of 640,000 cubic metres. bp also has 0.6Mtpa of regasification capacity at GDLNG for up to 12 years starting from the beginning of 2021. bp imports LNG from our global portfolio and delivers regasified natural gas via the terminal to power plant and city gas customers in Guangdong province under long-term sales contracts.

In Azerbaijan, bp operates two PSAs, Azeri-Chirag-Gunashli (ACG) (bp 30.37%) and Shah Deniz (bp 29.99%) and also holds a number of other exploration leases.

- On 16 April bp, as operator of the Azeri-Chirag-Gunashli (ACG) field, announced the start-up of oil production from the new Azeri Central East (ACE) platform as part of the giant ACG field development, which is the first remotely operated offshore platform in the Caspian.
- On 4 June a new gas sales agreement (GSA) was signed with the Turkish state-owned company BOTAS covering the period 2025-2030. This is the fourth GSA between Shah Deniz and BOTAS since the start of production from the field in 2006.
- On 19 July bp and SOCAR signed a protocol to extend the Shafag-Asiman exploration period until the end of June 2025 to allow for bp and SOCAR to continue discussions on the terms of any potential follow-on exploration activity.
- On 20 September the ACG joint venture partners announced the signing of an addendum to the existing PSA which enables the parties to progress the exploration, appraisal, development of and production from the non-associated natural gas reservoirs of the ACG field (bp operator with 30.37% equity).
- On 20 September bp and the State Oil Company of the Azerbaijan Republic (SOCAR) signed a memorandum of understanding announcing the parties' intention for bp to join SOCAR in two exploration and development blocks in the Azerbaijan sector of the Caspian Sea. The first block is the Karabagh oil field, and the second block is the Ashrafi – Dan Ulduzu – Aypara area, containing a number of existing discoveries and prospective structures.

Naftiran Intertrade Co Ltd (NICO), a subsidiary of the National Iranian Oil Company, holds a 10% interest in the Shah Deniz joint venture. For information on the exclusion of this project from EU and US trade sanctions, see International trade sanctions on page 334.

bp holds a 30.1% interest in and operates the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. The 1,768-kilometre pipeline transports oil from the ACG oilfield and condensate from the Shah Deniz gas and condensate field in the Caspian Sea, along with other third-party oil, to the eastern Mediterranean port of Ceyhan. The pipeline has a capacity of 1mmboe/d, with an average throughput in 2024 of 612mboe/d.

bp (as operator of Azerbaijan International Operating Company and the Georgian Pipeline Company for the Georgian section) also operates the Western Route Export Pipeline (WREP) that transports ACG oil to Supsa on the Black Sea coast of Georgia, with an average throughput of 2mboe/d in 2024. Exports through the pipeline have been suspended since May 2022 (with occasional short-term exports driven by operational needs) due to lack of nominations from the shipper group. In current market conditions WREP serves as a contingency export route for ACG crude product.

bp holds a 29.99% interest in and operates certain parts of the 693-kilometre South Caucasus Pipeline (SCP). The pipeline takes gas from the Shah Deniz field in Azerbaijan through Georgia to the Turkish border and has a capacity of 440mboe/d (including expansion), with average throughput in 2024 of 389mboe/d.

bp also holds a 12% interest in the Trans Anatolian Natural Gas Pipeline (TANAP). The pipeline takes Shah Deniz gas from the Turkish border and transports it to Eskisehir in Türkiye and to the Greek border where it connects with the Trans Adriatic Pipeline (TAP). The current capacity of TANAP is 275mboe/d and the average throughput in 2024 was 263mboe/d. bp has a 20% interest in TAP, which takes gas through Greece and Albania into Italy. The current capacity of TAP is 167mboe/d and the total average throughout in 2024 was 177mboe/d. TAP throughput exceeded capacity during 2024 due to high flow tests taking place during the year.

- On 16 September bp announced it had agreed for Apollo-managed funds to purchase a non-controlling stake in BP Pipelines TAP Limited, the bp subsidiary that holds a 20% share in TAP. bp remains the controlling shareholder of BP Pipelines TAP Limited.

In Oman, bp operates Block 61, the largest tight gas development in the Middle East (bp 40%). bp also has a 50% interest in Block 77 with Eni (operator) in which an exploration well was spudded in October 2023. Currently the prospect is under evaluation.

In Abu Dhabi, bp holds a 10% interest in the ADNOC Onshore concession. We also have a 10% equity shareholding in ADNOC LNG and a 10% shareholding in the shipping company NGSCO. ADNOC LNG supplied approximately 5.9Mt of LNG (0.8bcfe/d regasified) in 2024. bp's interest in the ADNOC Onshore concession expires at the end of 2054.

- In July bp made the final investment decision to take a 10% interest in the planned 9.6mmtpa Ruwais LNG project, subject to receipt of appropriate merger clearances.

In 2016 bp signed an enhanced technical service agreement for the duration of ten years for south and east Kuwait conventional oilfields, which includes the Burgan field, with Kuwait Oil Company.

In India, we have a participating interest in two oil and gas PSAs (KG D6 33.33% and NEC25 33.33%), and two oil and gas blocks under a revenue sharing contract (KG-UDWHP-2018/1 40% and KG-UDWHP-2022/1 40%), all operated by Reliance Industries Limited (RIL). We also have a 50% stake in India Gas Solutions Private Limited, a joint venture with RIL, for the sourcing and marketing of gas in India.

- In February 2025 bp and Oil and Natural Gas Corporation Limited (ONGC) have signed agreement under which bp will serve as the technical services provider for ONGC's Mumbai High field, India's largest oil and gas field. The scope of this bid award is to review the field performance and identify improvements in reservoir, facilities and wells to enhance production from the Mumbai High field over a 10-year contract period.

In the Asian part of Indonesia, bp holds an interest in the Andaman II PSC exploration block (operated by Harbour Energy), located offshore North Sumatra, and in Agung I and Agung II exploration blocks offshore Indonesia. Agung I covers over 6,000km^2 off the coast of Bali and East Java and Agung II spans almost 8,000km^2 offshore South Sulawesi, West Nusa Tenggara and East Java.

In Iraq, bp holds a 49% participating interest in Basra Energy Company Limited (BECL). BECL is an incorporated joint venture (IJV) company owned by bp (49%) and PetroChina (51%) and acts as Rumaila lead contractor since 2022.

- On 25 February 2025 bp reached agreement on all contractual terms with the government of the Republic of Iraq to invest in several giant oil fields in Kirkuk providing for the rehabilitation and redevelopment of the fields, spanning oil, gas, power and water with potential for investment in exploration. The agreement is subject to final governmental ratification.

Australasia

bp has activities in Australia and Eastern Indonesia.

In Australia bp is one of six participants in the North West Shelf (NWS) venture, which has been producing LNG, pipeline gas, condensate, LPG and oil since the 1980s. Five partners hold interest in the gas infrastructure (bp 16.67%) and six partners hold interest in the gas and condensate reserves (bp 15.78%). The NWS venture is one of the largest LNG export projects in the region, with five LNG trains in operation, and also supplies domestic gas into the Western Australia market. bp's net share of the capacity of NWS LNG trains 1-5 is 2.67Mt (15.78% of 16.9mtpa gross) of LNG per year. This will be reduced in 2025 as one LNG train was taken offline in late 2024. bp is also one of four participants in the Browse LNG venture (bp 44.33%).

- In December Woodside and Chevron agreed to an asset swap under which Woodside will acquire Chevron's interest in the North West Shelf (NWS) Project, the NWS Oil Project and the Angel Carbon Capture and Storage (CCS) Project. This will reduce the number of NWS venture partners to five upon expected completion in 2026.

bp also has a 50% interest in the WA-541 exploration title in Western Australia's offshore Northern Carnarvon basin. The joint venture, operated by Santos, is working towards the drilling of two commitment wells.

In Papua Barat, Eastern Indonesia, bp operates the Tangguh LNG plant (bp 40.22%). The plant consists of 3 trains with total production capacity of 11.4Mtpa. The Tangguh asset comprises thirty production wells, four offshore platforms, three LNG processing trains, and two LNG loading facilities. Tangguh supplies LNG to customers in Indonesia, Mexico, China, South Korea, Taiwan and Japan through a combination of long, medium and spot contracts.

- On 21 November bp, on behalf of the Tangguh production sharing contract partners, announced a final investment decision on the $7 billion Tangguh Ubadari, CCUS, Compression project (UCC), which has the potential to unlock around 3 trillion cubic feet of additional gas resources in Indonesia to help meet growing energy demand in Asia.

Oil and natural gas

Resource progression

bp manages its hydrocarbon resources in three major categories: prospect inventory, contingent resources and reserves. When a discovery is made, volumes usually transfer from the prospect inventory to the contingent resources category. The contingent resources move through various sub-categories as their technical and commercial maturity increases through appraisal activity.

At the point of final investment decision, most proved reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. When part of a well's proved reserves depends on a later phase of activity, only that portion of proved reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will typically occur at the point of first oil or gas production. Major development projects typically take one to five years from the time of initial booking of PUD to the start of production. Changes to proved reserves bookings may be made due to analysis of new or existing data concerning production, reservoir performance, commercial factors and additional reservoir development activity.

Volumes can also be added or removed from our portfolio through acquisition or divestment of properties and projects. When we dispose of an interest in a property or project, the volumes associated with our adopted plan of development for which we have a final investment decision will be removed from our proved reserves upon completion of the transaction. When we acquire an interest in a property or project, the volumes associated with the existing development and any committed projects will be added to our proved reserves if bp has made a final investment decision and they satisfy the SEC's criteria for attribution of proved status. Following the acquisition, additional volumes may be progressed to proved reserves from non-proved reserves or contingent resources.

Non-proved reserves and contingent resources in a field will only be recategorized as proved reserves when all the criteria for attribution of proved status have been met and the volumes are included in the business plan and scheduled for development, typically within five years. bp will only book proved reserves where development is scheduled to commence after more than five years if these proved reserves satisfy the SEC's criteria for attribution of proved status and bp management has reasonable certainty that these proved reserves will be produced.

At the end of 2024 bp had no proved undeveloped reserves held for more than five years in our onshore US developments.

Over the past five years, bp has annually progressed a five-year average of 19% (17% for 2023 five-year average) of our group proved undeveloped reserves (including the impact of disposals and price acceleration effects in PSAs) to proved developed reserves. This equates to a turnover time of five years.

Proved reserves as estimated at the end of 2024 meet bp's criteria for project sanctioning and SEC tests for proved reserves. We have not halted or changed our commitment to proceed with any material project to which proved undeveloped reserves have been attributed.

In 2024 we progressed 402mmboe of proved undeveloped reserves (325mmboe for our subsidiaries★ alone) to proved developed reserves through ongoing investment in our subsidiaries' and equity-accounted entities' development activities. Total development expenditure, excluding midstream activities, was $11,541 million in 2024 ($7,953 million for subsidiaries and $3,588 million for equity-accounted entities). Of the $7,953 million of total development expenditure for our subsidiaries, approximately $2,800 million was used for development activity to progress proved undeveloped reserves to proved developed. Of the $3,588 million development expenditure for our equity-accounted entities, approximately $1,100 million was used for development activity to progress proved undeveloped reserves to proved developed. The major areas with progressed volumes in 2024 were the US, Azerbaijan, Southern Cone and Middle East.

Revisions of previous estimates for proved undeveloped reserves are due to changes relating to field performance, well results, revisions to future activity plans (including alignment with our investment criteria and changes to the macroeconomic climate) or changes in commercial conditions including price impacts. The net revisions to previous estimates across both our subsidiaries and our equity-accounted entities include net positive revisions driven by revisions to activity plans and revisions due to field performance, and net negative revisions driven by price and well results. The net revisions to previous estimates across only our subsidiaries include net positive revisions driven by revisions to activity plans and net negative revisions driven by price, field performance and well results. In each case, none of these factors resulted in revisions that were material to the group as a whole. The following tables describe the changes to our proved undeveloped reserves position through the year for our subsidiaries and equity-accounted entities, and for our subsidiaries alone.

	volumes in mmboe[a]
Subsidiaries and equity-accounted entities	Group
Proved undeveloped reserves at 1 January 2024	2,558
Revisions of previous estimates	(5)
Price	(100)
Revision of future activity plans	130
Field performance	1
Well results	(37)
Improved recovery	4
Discoveries and extensions	237
Purchases	13
Sales	(19)
Total in year proved undeveloped reserves changes	229
Proved developed reserves reclassified as undeveloped	3
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(402)
Proved undeveloped reserves at 31 December 2024	**2,387**

Subsidiaries only	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2024	2,006
Revisions of previous estimates	18
Price	(99)
Revision of future activity plans	152
Field performance	(3)
Well results	(33)
Improved recovery	2
Discoveries and extensions	180
Purchases	6
Sales	(15)
Total in year proved undeveloped reserves changes	191
Proved developed reserves reclassified as undeveloped	2
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(325)
Proved undeveloped reserves at 31 December 2024	**1,875**

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

bp bases its proved reserves estimates on the requirement of reasonable certainty, with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements. bp only applies technologies that have been field-tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. bp applies high-resolution seismic data for the identification of reservoir extent and fluid contacts only where there is an overwhelming track record of success in its local application. In certain cases bp uses numerical simulation as part of a holistic assessment of recovery factor for its fields, where these simulations have been field-tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In certain deepwater fields bp has booked proved reserves before production flow tests are conducted, in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. To determine reasonable certainty of commercial recovery, bp employs a general method of reserves assessment that relies on the integration of three types of data:

- Well data used to assess the local characteristics and conditions of reservoirs and fluids.
- Field-scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control.
- Data from relevant analogous fields.

Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. bp considers the integration of this data in certain cases to be superior to a flow test in providing understanding of overall reservoir performance. The collection of data from logs, cores,

★ See glossary on **page 351**

wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short-term flow test. There is a strong track record of proved reserves recorded using these methods, validated by actual production levels.

Governance

bp's centrally controlled process for proved reserves estimation approval forms part of a holistic and integrated system of internal control. It consists of the following elements:

- Accountabilities of certain officers of the group to ensure that there is review and approval of proved reserves bookings independent of the operating business, and that there are effective controls in the approval process and verification that the proved reserves estimates and the related financial impacts are reported in a timely manner.
- Capital allocation processes, whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group's business plan. A formal review process exists to ensure that both technical and commercial criteria are met prior to the commitment of capital to projects.
- Internal audit, whose role is to consider whether the group's system of internal control is adequately designed and operating effectively to respond appropriately to the risks that are significant to bp.
- Approval hierarchy, whereby proved reserves changes above certain threshold volumes require immediate review and all proved reserves require annual central authorization and have scheduled periodic reviews. The frequency of periodic reviews ensures that 100% of the bp proved reserves base undergoes central review every three years.

bp's vice president of reserves is the individual primarily responsible for overseeing the preparation of the reserves estimate. He has more than 30 years of diversified industry experience in reserves estimation with the past four years managing the governance and compliance. He is a past Chairman of the Society of Petroleum Engineers (Russia & Caspian) and a member of the United Nations Economic Commission for Europe Expert Group on Resource Management.

No specific portion of compensation bonuses for senior management is directly related to proved reserves targets. Additions to proved reserves is one of several indicators by which the performance of the gas & low carbon and oil production & operations segments is assessed by the remuneration committee for the purposes of determining compensation bonuses for the executive directors. Other indicators include a number of financial and operational measures.

bp's variable pay programme for the other senior managers in the gas & low carbon and oil production & operations segments is based on individual performance contracts. Individual performance contracts are based on agreed items from the business performance plan, one of which, if chosen, could relate to proved reserves.

Compliance

International Financial Reporting Standards (IFRS) do not provide specific guidance on reserves disclosures. bp estimates proved reserves in accordance with SEC Rule 4-10 (a) of Regulation S-X and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins as issued by the SEC staff.

By their nature, there is always risk involved in the ultimate development and production of proved reserves including, but not limited to: final regulatory approval; the installation of new or additional infrastructure, as well as changes in oil and gas prices; changes in operating and development costs; and the continued availability of additional development capital. All the group's proved reserves held in subsidiaries and equity-accounted entities are estimated by the group's petroleum engineers, or by independent petroleum engineering consulting firms and then assured by the group's petroleum engineers.

Netherland, Sewell & Associates (NSAI), an independent petroleum engineering consulting firm, has estimated the net proved crude oil, condensate, natural gas liquids (NGLs) and natural gas reserves, as of 31 December 2024, of certain properties owned by bp in the US Lower 48. The properties evaluated by NSAI account for 100% of bp's net proved reserves in the US Lower 48 as of 31 December 2024. The net proved reserves estimates prepared by NSAI were prepared in accordance with the reserves definitions of Rule 4-10(a)(1)-(32) of Regulation S-X. All reserves estimates involve some degree of uncertainty. bp has filed NSAI's independent report on its reserves estimates as an exhibit to this Annual Report and Form 20-F 2024 filed with the SEC.

Our proved reserves are associated with both concessions (tax and royalty arrangements) and agreements where the group is exposed to the upstream risks and rewards of ownership, but where our entitlement to the hydrocarbons is calculated using a more complex formula, such as with PSAs. In a concession, the consortium of which we are a part is entitled to the proved reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the proved reserves, and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves.

We disclose our share of proved reserves held in equity-accounted entities (joint ventures★ and associates★), although we do not control these entities or the assets held by such entities.

bp's estimated net proved reserves and proved reserves replacement

94% of our total proved reserves of subsidiaries at 31 December 2024 were held through joint operations★ (94% in 2023), and 23% of the proved reserves were held through such joint operations where we were not the operator (25% in 2023).

Estimated net proved reserves of crude oil at 31 December 2024[abc]

			million barrels
	Developed	Undeveloped	Total
UK	**104**	**63**	**167**
US	**653**	**472**	**1,125**
Rest of North America	**–**	**–**	**–**
South America[d]	**1**	**4**	**5**
Africa	**1**	**–**	**1**
Rest of Asia	**716**	**305**	**1,021**
Australasia	**9**	**1**	**10**
Subsidiaries	**1,483**	**846**	**2,329**
Equity-accounted entities	**558**	**339**	**896**
Total	**2,041**	**1,184**	**3,225**

Estimated net proved reserves of natural gas liquids at 31 December 2024[ab]

			million barrels
	Developed	Undeveloped	Total
UK	**2**	**–**	**3**
US	**202**	**246**	**447**
Rest of North America	**–**	**–**	**–**
South America	**1**	**–**	**1**
Africa	**–**	**–**	**–**
Rest of Asia	**–**	**–**	**–**
Australasia	**1**	**–**	**1**
Subsidiaries	**206**	**246**	**452**
Equity-accounted entities	**16**	**6**	**22**
Total	**222**	**252**	**474**

Estimated net proved reserves of liquids[d]★

			million barrels
	Developed	Undeveloped	Total
Subsidiaries	**1,689**	**1,092**	**2,781**
Equity-accounted entities	**573**	**344**	**918**
Total	**2,263**	**1,436**	**3,699**

Estimated net proved reserves of natural gas at 31 December 2024[ab]

			billion cubic feet
	Developed	Undeveloped	Total
UK	**162**	**29**	**190**
US	**2,600**	**2,412**	**5,012**
Rest of North America	**—**	**—**	**—**
South America[e]	**379**	**350**	**730**
Africa	**161**	**—**	**161**
Rest of Asia	**3,026**	**1,320**	**4,346**
Australasia	**1,254**	**431**	**1,685**
Subsidiaries	**7,582**	**4,542**	**12,124**
Equity-accounted entities	**1,686**	**976**	**2,662**
Total	**9,268**	**5,518**	**14,786**

Estimated net proved reserves on an oil equivalent basis

			million barrels of oil equivalent
	Developed	Undeveloped	Total
Subsidiaries	**2,997**	**1,875**	**4,871**
Equity-accounted entities	**864**	**513**	**1,377**
Total	**3,860**	**2,387**	**6,248**

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently, and include non-controlling interests in consolidated operations. We disclose our share of reserves held in joint ventures and associates that are accounted for by the equity method, although we do not control these entities or the assets held by such entities.
b The 2024 marker prices used were Brent $81.171/bbl (2023 $83.27/bbl and 2022 $101.24/bbl) and Henry Hub $2.065/mmBtu (2023 $2.58/mmBtu and 2022 $6.19/mmBtu).
c Includes condensate.
d Includes 1.7 million barrels of liquids in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
e Includes 219 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

Proved reserves replacement

Total hydrocarbon proved reserves at 31 December 2024, on an oil equivalent basis including equity-accounted entities, decreased by 8% compared with 31 December 2023 (8% decrease for subsidiaries and 4% decrease for equity-accounted entities). Natural gas decreased by 15% (19% decrease for subsidiaries and 5% increase for equity-accounted entities).

There was a net decrease from acquisitions and disposals of 72mmboe within our US, Trinidad and North Africa subsidiaries.

The proved reserves replacement ratio★ is the extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, and extensions and discoveries. For 2024, the proved reserves replacement ratio excluding acquisitions and disposals was 50% (47% in 2023 and 20% in 2022) for subsidiaries and equity-accounted entities, 52% for subsidiaries alone and 37% for equity-accounted entities alone. There was a net decrease (96mmboe) of reserves due to lower gas and oil prices, primarily in our US subsidiaries, partly offset by an increase in reserves in some of our PSAs in Azerbaijan.

In 2024 net additions to the group's proved reserves (excluding production, sales and purchases of reserves-in-place) amounted to 441mmboe (391mmboe for subsidiaries and 50mmboe for equity-accounted entities), through revisions to previous estimates including price, improved recovery from, and extensions to, existing fields, and discoveries of new fields. The majority of subsidiary additions were through revisions to previous estimates and extensions to existing fields and discoveries of new fields, where they represented a mixture of proved developed and proved undeveloped reserves. The principal proved reserves additions in our subsidiaries by region were in the US and the Middle East. The principal reserves additions in our equity-accounted entities were in PAEG.

In January 2024 it was reported that the Oslo District Court had determined that certain development permits granted by the Norwegian government during 2023 were invalid. This includes development permits for two fields in which Aker bp has an interest. The court's decision is not final and could be appealed. If bp's equity-accounted share of the reserves attributable to these two fields is removed from the calculation of bp's 2024 proved reserves ratio, that ratio would remain the same. Removal of the same reserves from bp's 2024 reporting would impact proved hydrocarbon reserves for the group, proved undeveloped reserves and estimated net proved reserves on an oil equivalent basis, amongst other reported measures, both for equity-accounted entities and group.

25% of our proved reserves are associated with PSAs. The countries in which we produced under PSAs in 2024 were Angola, Azerbaijan, Egypt, India, Indonesia, Mexico and Oman. In addition, the technical service contract (TSC)★ governing our investment in the Rumaila field in Iraq functions as a PSA.

The group holds no licences in our PSAs or TSCs due to expire within the next three years that would have a significant impact on bp's reserves or production, including undeveloped acreage.

For further information on our reserves see page 230.

★ See glossary on **page 351**

bp's net production by country – crude oil[a] and natural gas liquids

thousand barrels per day

bp net share of production[b]

	Crude oil 2024	Crude oil 2023	Crude oil 2022	Natural gas liquids 2024	Natural gas liquids 2023	Natural gas liquids 2022
Subsidiaries						
UK	**70**	74	80	**4**	5	5
Total Europe	**70**	74	80	**4**	5	5
Lower 48 onshore[c]	**86**	69	71	**84**	66	56
Gulf of America deepwater	**290**	266	225	**23**	22	19
Total US	**376**	335	296	**107**	88	76
Canada[cd]	**—**	—	15	**—**	—	—
Total Rest of North America	**—**	—	15	**—**	—	—
Total North America	**376**	335	311	**107**	88	76
Trinidad and Tobago	**4**	4	5	**4**	4	4
Total South America	**4**	4	5	**4**	4	4
Angola[c]	**—**	—	49	**—**	—	—
Egypt	**19**	28	28	**1**	1	—
Algeria[c]	**—**	1	5	**—**	1	6
Total Africa	**19**	29	83	**1**	2	6
Abu Dhabi	**202**	197	195	**—**	—	—
Azerbaijan	**66**	70	73	**—**	—	—
Iraq[c]	**—**	—	15	**—**	—	—
India[g]	**6**	4	—	**—**	—	—
Oman	**23**	22	24	**—**	—	—
Total Rest of Asia	**297**	293	307	**—**	—	—
Total Asia	**297**	293	307	**—**	—	—
Australia[c]	**7**	8	11	**2**	2	2
Eastern Indonesia	**2**	2	1	**—**	—	—
Total Australasia	**9**	10	12	**2**	2	2
Total subsidiaries	**775**	745	797	**117**	100	93
Equity-accounted entities (bp share)						
Rosneft[e] (Russia, Egypt)	**—**	—	144	**—**	—	—
Argentina	**52**	51	51	**1**	1	1
Mexico	**3**	5	6	**—**	—	—
Bolivia	**1**	1	2	**—**	—	—
Egypt	**—**	—	—	**2**	2	3
Norway	**58**	60	47	**2**	3	2
Russia	**—**	—	7	**—**	—	—
Iraq	**69**	62	25	**—**	—	—
Angola	**82**	82	33	**4**	4	2
Total equity-accounted entities	**266**	261	314	**9**	9	9
Total subsidiaries and equity-accounted entities[f]	**1,041**	1,006	1,111	**126**	109	102

a Includes condensate.
b Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
c In 2024, bp disposed of certain Lower 48 onshore interests in the US. In 2023, bp disposed of its interests in Algeria. In 2022, bp disposed of its interests in Angola, its interest in Sunrise Oil Sands in Canada, its interest in Rumaila in Iraq, and certain Lower 48 onshore interests in the US and certain offshore interests in Australia.
d All of the production from Canada in subsidiaries is bitumen.
e 2022 reflects bp's estimated share of Rosneft production for the period 1 January to 27 February, averaged over the year (see Financial statements – Note 1). Includes production in respect of the non-controlling interest in Rosneft, including production held through bp's interests in Russia other than Rosneft.
f Includes 2 net mboe/d of NGLs from processing plants in which bp has an interest (2023 2mboe/d and 2022 2mboe/d).
g 2023 restated, previously reported in NGLs.

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

bp's net production by country – natural gas

			million cubic feet per day
	bp net share of production[a]		
	2024	2023	2022
Subsidiaries			
UK	**197**	247	271
Total Europe	**197**	247	271
Lower 48 onshore[b]	**1,530**	1,338	1,148
Gulf of America deepwater	**160**	149	143
Total US	**1,690**	1,486	1,291
Canada	**—**	—	—
Total Rest of North America	**—**	—	—
Total North America	**1,690**	1,486	1,291
Trinidad and Tobago[b]	**1,145**	1,191	1,276
Total South America	**1,145**	1,191	1,276
Egypt[b]	**904**	1,220	1,272
Algeria[b]	**—**	16	81
Total Africa	**904**	1,236	1,353
Azerbaijan	**748**	714	670
India	**303**	283	216
Oman	**604**	582	599
Total Rest of Asia	**1,655**	1,578	1,485
Total Asia	**1,655**	1,578	1,485
Australia	**276**	301	331
Eastern Indonesia	**606**	473	421
Total Australasia	**882**	774	752
Total subsidiaries[c]	**6,474**	6,512	6,428
Equity-accounted entities (bp share)			
Rosneft[d] (Russia, Canada, Egypt, Vietnam)	**—**	—	238
Argentina	**267**	247	238
Bolivia	**33**	50	56
Mexico	**1**	2	2
Egypt	**9**	—	—
Norway	**55**	58	66
Russia	**—**	—	10
Angola	**76**	74	64
Total equity-accounted entities[c]	**440**	432	674
Total subsidiaries and equity-accounted entities	**6,914**	6,944	7,101

a Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
b In 2024, bp disposed of certain interests in Egypt and Trinidad and Tobago. In 2023, bp disposed of its interests in Algeria and certain Lower 48 onshore interests in the US. In 2022, bp disposed of certain Lower 48 onshore interests in the US.
c Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field, but the related reserves are included in the group's reserves.
d 2022 reflects bp's estimated share of Rosneft production for the period 1 January to 27 February, averaged over the year (see Financial statements – Note 1). Includes production in respect of the non-controlling interest in Rosneft, including production held through bp's interests in Russia other than Rosneft.

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

The following tables provide additional data and disclosures in relation to our oil and gas operations.

Average sales price per unit of production (realizations★)[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
										$ per unit of production
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
2024										
Crude oil[b]	**80.81**	**—**	**74.73**	**—**	**81.89**	**75.21**	**—**	**81.28**	**70.21**	**77.77**
Natural gas liquids	**43.45**	**—**	**20.09**	**—**	**20.46**	**—**	**—**	**—**	**49.25**	**21.25**
Gas	**11.65**	**—**	**1.49**	**—**	**3.42**	**4.68**	**—**	**6.83**	**8.95**	**4.91**
2023										
Crude oil[b]	82.99	—	75.28	—	84.36	76.30	—	83.86	68.27	79.37
Natural gas liquids	46.52	—	19.26	—	30.76	44.41	—	—	33.47	23.79
Gas	16.71	—	2.08	—	3.58	4.82	—	7.72	8.89	5.60
2022										
Crude oil[b]	102.54	—	90.05	84.88	99.09	102.00	—	98.74	86.11	95.70
Natural gas liquids	60.41	—	31.72	—	60.55	54.78	—	—	54.20	37.00
Gas	33.45	—	5.61	3.68	7.65	5.21	—	11.81	12.33	9.29
Equity-accounted entities[c]										
2024										
Crude oil[b]	**—**	**80.10**	**—**	**—**	**79.21**	**78.60**	**—**	**73.86**	**—**	**77.84**
Natural gas liquids	**—**	**—**	**—**	**—**	**27.84**	**—**	**—**	**—**	**—**	**27.84**
Gas	**—**	**10.83**	**—**	**—**	**3.38**	**—**	**—**	**—**	**—**	**4.54**
2023										
Crude oil[b]	—	81.61	—	—	75.49	80.21	—	75.21	—	78.33
Natural gas liquids[d]	—	—	—	—	30.95	42.89	N/A	—	—	36.70
Gas	—	12.80	—	—	3.66	—	—	—	—	5.15
2022										
Crude oil[b]	—	71.14	—	—	78.05	86.73	102.84	90.16	—	90.18
Natural gas liquids[d]	—	—	—	—	46.64	—	N/A	—	—	46.64
Gas	—	24.23	—	—	4.75	—	4.35	—	—	6.91

Average production cost per unit of production[e]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
										$ per unit of production
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
2024	**13.74**	**—**	**9.33**	**—**	**5.27**	**3.57**	**—**	**2.89**	**1.78**	**6.17**
2023	10.69	—	9.61	—	4.53	2.52	—	2.81	2.09	5.78
2022	10.36	—	9.70	15.36	3.92	5.02	—	3.52	2.04	6.07
Equity-accounted entities										
2024	**—**	**6.16**	**—**	**—**	**20.40**	**18.30**	**—**	**22.88**	**—**	**17.37**
2023	—	6.22	—	—	17.87	15.46	—	16.41	—	14.38
2022	—	6.01	—	—	15.55	21.01	7.39	20.81	—	11.47

a Units of production are barrels for liquids and thousands of cubic feet for gas. Realizations include transfers between businesses, except in the case of Russia.
b Includes condensate.
c In certain countries it is common for equity-accounted entities' agreements to include pricing clauses that require selling a significant portion of the entitled production to local governments or markets at discounted prices.
d Natural gas liquids for Russia are included in crude oil.
e Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

Additional information for customers & products

Reconciliation of customers & products RC profit before interest and tax to underlying RC profit before interest and tax to adjusted EBITDA★ by business

			$ million
	2024	2023	2022
RC profit (loss) before interest and tax for customers & products	**(1,560)**	4,230	8,869
Less: Adjusting items gains (charges)	**(4,077)**	(2,183)	(1,920)
Underlying RC profit before interest and tax for customers & products	**2,517**	6,413	10,789
By business:			
customers – convenience & mobility	**2,584**	2,644	2,966
Castrol – included in customers	***831***	*730*	*700*
products – refining & trading	**(67)**	3,769	7,823
Add back: Depreciation, depletion and amortization	**3,957**	3,548	2,870
By business:			
customers – convenience & mobility	**2,135**	1,736	1,286
Castrol – included in customers	***176***	*167*	*153*
products – refining & trading	**1,822**	1,812	1,584
Adjusted EBITDA for customers & products	**6,474**	9,961	13,659
By business:			
customers – convenience & mobility	**4,719**	4,380	4,252
Castrol – included in customers	***1,007***	*897*	*853*
products – refining & trading	**1,755**	5,581	9,407

Sales volume

			thousand barrels per day
	2024	2023	2022
Marketing sales[a]	**2,714**	2,718	2,613
Trading/supply sales[b]	**373**	358	350
Total refined product sales	**3,087**	3,076	2,963
Crude oil[c]	**86**	102	184
Total	**3,173**	3,178	3,147

a Marketing sales include branded and unbranded sales of refined fuel products and lubricants to business-to-business and business-to-consumer customers, including service station dealers, jobbers, airlines, small and large resellers such as hypermarkets, and the military.
b Trading/supply sales are fuel sales to large unbranded resellers and other oil companies.
c Crude oil sales relate to third-party transactions executed primarily by supply, trading and shipping. In addition, reported crude oil sales in 2024 includes 52 thousand barrels per day (2023 68 thousand barrels per day and 2022 67 thousand barrels per day) relating to volumes sold directly by the gas & low carbon energy and oil production & operations segments.

In the table above, volumes of crude oil and refined product trading/supply sales are presented on a basis consistent with income statement presentation. These figures do not correspond to actual volumes of physically traded energy products and are not intended for use in assessing emissions volumes or carbon intensity. Marketing volumes shown represent physically delivered transactions regardless of income statement presentation of such transactions.

Retail sites[a]

			Number of bp-branded retail sites
	2024	2023	2022
US	**8,500**	8,200	7,750
Europe	**7,750**	8,050	8,150
Rest of world	**4,950**	4,850	4,750
Total	**21,200**	21,100	20,650

a Reported to the nearest 50. Includes sites operated by dealers, jobbers, franchisees or brand licensees or joint venture (JV) partners, under the bp brand. These may move to and from the bp brand as their fuel supply agreement or brand licence agreement expires and is renegotiated in the normal course of business. Retail sites are primarily branded bp, *ARCO*, *Amoco*, *Aral*, *Thorntons* and *TravelCenters of America*, and also include sites in India through our Jio-bp JV.

Refinery throughputs[abcde]

			thousand barrels per day
	2024	2023	2022
US	**612**	662	678
Europe	**782**	749	804
Rest of world	**—**	—	22
Total	**1,394**	1,411	1,504

			%
Refining availability★	**94.3**	96.1	94.5

a This does not include bp's interest in Pan American Energy Group.
b Refinery throughputs reflect crude oil and other feedstock volumes.
c On 28 February 2023, bp completed the sale of its 50% interest in the bp-Husky Toledo refinery in Ohio, US to Cenovus Energy, its partner in the facility.
d On 1 December 2024, bp completed the sale of its 50% ownership in the SAPREF refinery to the South African state-owned entity Central Energy Fund SOC Ltd.
e On 6 February 2025 bp announced its intention to market its Ruhr Oel GmbH – BP Gelsenkirchen operation in Germany for potential sale, including its refinery in Gelsenkirchen and DHC Solvent Chemie GmbH in Mülheim an der Ruhr.

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Refinery capacity

The following table[ab] summarizes bp's average daily crude distillation capacities as at 31 December 2024.

	Country	Refinery	Crude distillation capacities[c] thousand barrels per day
US			
US North West	US	Cherry Point	**251**
US Mid West		Whiting	**440**
			691
Europe			
North West Europe	Germany	Gelsenkirchen[d]	**265**
		Lingen	**97**
	Netherlands	Rotterdam	**394**
Mediterranean	Spain	Castellón	**110**
			866
Total capacity at 31 December 2024			**1,557**

a This does not include bp’s interest in Pan American Energy Group.
b On 1 December 2024 bp completed the sale of its 50% ownership in the SAPREF refinery to the South African state-owned entity, Central Energy Fund SOC Ltd.
c Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period under normal operational conditions.
d On 6 February 2025 bp announced its intention to market its Ruhr Oel GmbH – BP Gelsenkirchen operation in Germany for potential sale, including its refinery in Gelsenkirchen and DHC Solvent Chemie GmbH in Mülheim an der Ruhr.

Environmental expenditure

			$ million
	2024	2023	2022
Operating expenditure	**575**	524	416
Capital expenditure	**393**	329	224
Clean-ups	**20**	23	16
Additions to environmental remediation provision	**254**	228	502
Increase (decrease) in decommissioning provision	**942**	920	1,248

Operating and capital expenditure on the prevention, control, treatment or elimination of air and water emissions and solid waste is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction that includes, for example, normal operations and maintenance expenditure. The figures for environmental operating and capital expenditure in the table are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

Environmental operating expenditure of $575 million in 2024 (2023 $524 million) showed an overall increase of 10%, largely due to increased expenditure in BP Products North America.

Environmental capital expenditure of $393 million in 2024 (2023 $329 million) showed an overall increase of 19%, largely due to increased expenditure for BP Products North America.

Clean-up costs were $20 million in 2024 (2023 $23 million), representing oil spill clean-up costs and other associated remediation and disposal costs.

In addition to operating and capital expenditure, we also establish provisions for future environmental remediation work. Expenditure against such provisions normally occurs in subsequent periods and is not included in environmental operating expenditure reported for such periods.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The extent and cost of future environmental restoration, remediation and abatement programmes are inherently difficult to estimate. They often depend on the extent of contamination, and the associated impact and timing of the corrective actions required, technological feasibility and bp's share of liability. Though the costs of future programmes could be significant and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the group's overall results of operations or financial position. For further information, see Note 1 - Significant judgements and estimates: provisions.

Additions to our environmental remediation provision reflect new liabilities and scope/cost reassessments of the remediation plans of a number of our sites, primarily in the US. The charge for environmental remediation provisions in 2024 arising from new and acquired sites was $24 million (2023 $37 million and 2022 $67 million).

In addition, we make provisions on installation of our oil and gas producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility, a provision is established that represents the discounted value of the expected future cost of decommissioning the asset.

In 2024, the net increase in the decommissioning provision was primarily due to recognition of additional provisions and changes in cost estimate assumptions.

We undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments.

Provisions for environmental remediation and decommissioning are usually established on a discounted basis, as required by IAS 37 'Provisions, Contingent Liabilities and Contingent Assets'.

Further details of decommissioning and environmental provisions appear in Financial statements – Note 23.

Regulation of the group's business

Our businesses and operations are subject to the laws and regulations applicable in each country, state or other regional or local area in which they occur. These cover virtually all aspects of bp's activities and include matters such as the acquisition of rights to develop and operate projects, production rates, royalties, environmental, health and safety protection, fuel specifications and transportation, trading, pricing, anti-trust, export, taxes, and foreign exchange.

Oil and gas contractual and regulatory framework

The terms and conditions of the leases, licences and contracts under which our upstream oil and gas interests are held vary from country to country. These leases, licences and contracts are generally granted by or entered into with a government entity or state-owned or controlled company and are sometimes entered into with private property owners. Arrangements with governmental or state entities usually take the form of licences or production-sharing agreements★ (PSAs), although arrangements with private entities and US government entities are usually by lease.

Licences (or concessions) give the holder the right to explore for, develop and produce a commercial discovery. Under a licence, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the licence holder is entitled to all production, minus any royalties that are payable in kind. A licence holder is generally required to pay production taxes or royalties, which may be in cash or in kind.

In certain countries, separate licences are required for exploration and production activities, and in some cases production licences are limited to only a portion of the area covered by the original exploration licence.

PSAs entered into with a government entity or state-owned or state-controlled company generally require bp (alone or with other contracting companies) to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any. Less typically, bp may explore for, develop and produce hydrocarbons under a service agreement with the host entity in exchange for reimbursement of costs and/or a fee paid in cash rather than production.

bp frequently conducts its exploration and production activities in joint arrangements or co-ownership arrangements with other international oil companies, state-owned or -controlled companies and/or private companies. Conventionally, all costs, benefits, rights, obligations, liabilities and risks incurred in carrying out joint arrangement or co-ownership operations under a lease, licence or PSA are shared among the joint arrangement or co-owning parties according to agreed ownership interests which are set out in a joint operating agreement. To the extent that any liabilities arise, whether to governments or third parties, or between the joint arrangement parties or co-owners themselves, each joint arrangement party or co-owner will generally be liable under the terms of a joint operating agreement to meet these in proportion to its ownership interest. Any agreed allocation of liability amongst the joint arrangement parties is, however, often different to the position under the relevant licence, lease or PSA, which may provide for joint and several liability of the joint arrangement parties including for decommissioning obligations. In many upstream operations, a party (known as the operator) will be appointed (pursuant to a joint operating agreement) to carry out day to-day operations on behalf of the joint arrangement or co-ownership. The operator is typically one of the joint arrangement parties or a co-owner and will carry out its duties either through its own staff, or by contracting out various elements to third-party contractors or service providers. bp acts as operator on behalf of joint arrangements and co-ownerships in a number of countries.

Frequently, work (including drilling and related activities) will be contracted out to third-party service providers. The relevant contract will specify the work, the remuneration, and typically the risk allocation between the parties. Depending on the service to be provided, the contract may also contain provisions allocating risks and liabilities associated with pollution and environmental damage, damage to a well or hydrocarbon reservoirs and for claims from third parties or other losses. The allocation of those risks

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varies among contracts and is determined through negotiation between the parties.

In general, bp incurs income tax on income generated from production activities (whether under a licence or PSA). In addition, depending on the area, bp's production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed on oil and gas production profits and activities may be substantially higher than those imposed on other activities, for example in Egypt, the UK, the US and the United Arab Emirates.

Low carbon energy – renewables contractual and regulatory framework

The majority of our renewable assets are held indirectly through interests in incorporated joint ventures or special purpose entities (in either case, a Project Company). The renewables contractual and regulatory framework and the rights granted in relation to a renewable asset significantly vary from country to country. In some countries, the regulatory framework is still under development or subject to significant change as the renewables industry evolves.

In general terms the rights to a renewable asset are usually held by a Project Company through a package of assets that together form the renewable project owned by such Project Company, including:

- one or more leases, easements or licences over land or seabed granted by a public or private individual or entity that grant the Project Company rights to develop, build and operate the renewable asset in such areas of land or seabed;
- one or more generation licences that grant the Project Company the right to produce and sell the electricity to the market;
- an interconnection agreement that grants the Project Company the right to connect the power project into the grid;
- an offtake agreement which, depending on the country's electricity market, is entered into with a utility company, a corporate buyer or a public entity; and
- potentially, a subsidy mechanism in the form of a feed in tariff, contract for difference, hedging mechanism or renewable energy certificate to support the development of the project.

The risk allocation between the developer/generator and the host government or private entity has not been standardized in the industry. However, in general terms the Project Company bears the risk of the development, construction and operation of the renewable energy project and secures the financing for these operations and receives any profit from the revenue generated through the offtake agreement and/or subsidy mechanism (if available).

Greenhouse gas regulation

In December 2015, nearly 200 nations at the United Nations climate change conference in Paris (COP21) agreed to the Paris Agreement which aims to hold the increase in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. Signatories aim to reach global peaking of greenhouse gas (GHG) emissions as soon as possible and to undertake rapid reductions thereafter, so as to achieve a balance between human caused emissions and removals by sinks of GHGs in the second half of this century. The Paris Agreement commits all signatories to submit Nationally Determined Contributions (NDCs) (i.e. pledges or plans of climate action) and pursue domestic measures aimed at achieving the objectives of their NDCs. Signatories are required to submit revised NDCs every five years, and the revised NDCs are expected to be more ambitious with each revision. The first global stocktake of progress was published by the United Nations in September 2023 and further assessments will occur every five years. The UAE conference (COP28) in Dubai, which took place in November and December 2023, marked the conclusion and outcome of this first stocktake and reached a 'consensus' which includes calls for an acceleration of efforts towards the phase-down of unabated coal power and to transition away from fossil fuels in energy systems. The 2024 Baku conference (COP 29) included agreements in relation to finance and carbon markets.

More stringent national and regional measures relating to the transition to a lower carbon economy, such as the UK's 2050 net zero carbon emissions commitment, can be expected in the future. These measures could increase bp's production costs for certain products, increase compliance and litigation costs, increase demand for competing energy alternatives or products with lower-carbon intensity, and affect the sales and specifications of many of bp's products. Further, such measures could lead to constraints on production and supply and access to new reserves, particularly due to the long-term nature of many of bp's projects.

Certain current and announced GHG measures and developments potentially affecting bp's businesses in various markets in which bp operates are summarized below. For information on steps that bp is taking in relation to climate change issues and for details of bp's GHG reporting, see Sustainability – Net zero aims on page 48.

United States

In the US, bp's operations are affected by the regulation of GHGs in a number of ways. The federal Clean Air Act (CAA) and its various amendments regulate air emissions, permitting, fuel specifications and other aspects of our production, refining, distribution and marketing activities.

GHG Reporting Rule

The federal GHG Mandatory Reporting Rule requires operators of certain facilities and producers and importers/exporters of petroleum products to file annual GHG emissions reports with EPA quantifying direct GHG emissions from affected facilities, as well as the GHG emissions that would result from the release or combustion of the petroleum products imported, exported or produced. In addition, several states have their own GHG reporting rules.

Our US businesses are subject to increased GHG and other environmental requirements and regulatory uncertainty, including that the current or any future US administration could revise or revoke current or prior administration programmes, as well as the possibility of increased expenditures in having to comply with numerous diverse and non-uniform regulatory initiatives at the state and local levels.

US Inflation Reduction Act

The 2022 US Inflation Reduction Act (IRA) included a significant package of largely supply-side measures supporting low carbon energy sources and decarbonization technologies in the US. The impact of the IRA both on bp's businesses and more widely on the US economy is likely to depend on various factors that are currently uncertain, including the implementation of the incentive programmes by the US authorities through the Department of Energy (DOE), the Federal Aviation Administration (FAA), and other agencies, as well as regulatory initiatives at the federal, state and local levels.

In 2023, bp applied for various DOE and FAA grants related to certain of bp's low carbon energy and decarbonization projects. In 2024, DOE and FAA notified bp of its grant awards; bp and its co-applicants executed award agreements with the DOE, and bp is currently working with FAA on its award agreement. Regulatory uncertainty due to a change in U.S. administrations may significantly affect the implementation of IRA programmes.

Methane

In November 2023, the EPA promulgated the "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." These regulations are focused on methane emissions from oil and gas production at new and existing facilities and include significant requirements in the areas of fugitive emissions monitoring and repair, flaring, emission event reporting, process controller and pump emissions, and storage vessels.

The IRA requires EPA to collect an annual Waste Emissions Charge (WEC) on methane emissions from oil and natural gas facilities that exceed specific levels of emissions and methane intensity. The WEC is $900/metric ton of methane emissions occurring in 2024, $1,200/metric ton for emissions occurring in 2025, and $1,500/metric ton for emissions occurring in 2026 and thereafter. In November 2024, EPA promulgated regulations to implement the WEC provisions of the IRA.

Climate Resilience Funds

Several U.S. states, including New York, New Jersey and Vermont have enacted laws seeking recovery from historical greenhouse gas emitters to create climate resilience funds to address climate change impacts by financing infrastructure upgrades, disaster preparation, and other resilience projects. Other states, including California, Maryland and Massachusetts, are considering similar legislation. The extent and cost of to us of such future environmental climate fund programmes are difficult to estimate at this time.

Electricity

Other EPA GHG and environmental regulations affect electricity generation practices and prices and have an impact on the market for fuels used to generate electricity and on renewable energy installations. These regulations are in flux due to changes in approach between presidential administrations, as well as lawsuits challenging those regulations.

The 2022 Supreme Court decision in West Virginia v. EPA limited EPA's regulatory authority to require electricity 'generation shifting' (e.g. from coal to natural gas or renewable sources). In response to the West Virginia v. EPA decision, in April 2024 EPA promulgated new carbon pollution standards for coal and gas-fired power plants. The regulations significantly tighten emissions limits for those plants and will require some plants to install carbon capture technology.

Renewable Fuel Standard

EPA's Renewable Fuel Standard (RFS) regulations require transportation fuel sold in the US to contain a minimum volume of renewable fuels. In 2023, EPA announced a final rule establishing biofuel volume requirements and associated percentage standards for cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel for 2023-2025. Lawsuits were filed challenging this final rule and are ongoing.

State Low Carbon Fuel Standards

A number of states, municipalities and regional organizations continue to advance climate initiatives that affect our US operations. For example, certain state initiatives impose carbon-intensity reduction requirements on transportation fuels sold in those states. In November 2024, California updated its Low Carbon Fuel Standard (LCFS) to achieve a 30% reduction in carbon intensity by 2030 and a 90% reduction in carbon intensity by 2045. In 2021, Washington enacted state-wide carbon cap and invest legislation and a Clean Fuels Program (similar to California's LCFS) and finalized regulations implementing both of those programmes in 2022.

Mobile Source Emissions

US fuel markets are affected by EPA and National Highway Traffic Safety Administration (NHTSA) regulation of light, medium and heavy-duty vehicle emissions (both fuel economy and tailpipe standards) as well as for non-road engines and vehicles and certain large GHG stationary emission sources.

Light-duty and Medium Duty Vehicles

In March 2024, EPA promulgated a final rule entitled "Multi-Pollutant Emissions Standards for Model Year 2027 and Later Light-Duty and Medium-Duty Vehicles," which significantly tightens emissions standards for light- and medium-duty vehicles for model year (MY) 2027 and beyond and imposes new warranty, durability, and certification requirements, including for electric vehicles. The regulations are intended to spur emissions reductions technology on hydrocarbon-powered vehicles and to encourage the transition to electric vehicles. The regulations will phase in over MY 2027-2032.

Heavy-Duty Vehicles

In 2022, EPA promulgated a final rule entitled "Control of Air Pollution from New Motor Vehicles: Heavy Duty Engine and Vehicle Standards," which established new emission standards for oxides of nitrogen (NOx) and other pollutants for highway heavy-duty engines.

California Mobile Sources

The CAA authorizes the state of California to set its own separate vehicle emissions regulations, stricter than those at the federal level. Under CAA Section 209, California can apply to EPA for a waiver of federal pre-emption, and EPA is to grant this waiver absent certain disqualifying conditions. Under CAA Section 177, other states can adopt California standards or follow federal standards but cannot set their own. In 2020, California entered into voluntary framework agreements with several carmakers to meet more demanding vehicle emissions standards in California through MY 2026.

California Advanced Clean Cars Program

California's Advanced Clean Cars (ACC) regulations were originally enacted in 2012 for MY 2015 to 2025. The ACC program is a package of state regulations that set emissions standards for criteria pollutants, GHG emission standards for light-duty vehicles, and a ZEV sales mandate. In 2019, EPA and NTSA jointly promulgated the "Safer Affordable Fuel-Efficient Vehicles Rule Part One: One National Program (SAFE-1)," which effectively disallowed the ACC program. In 2021, EPA revoked SAFE-1, and the ACC program went back into force. In response to a legal challenge, the U.S. Court of Appeals upheld EPA's decision to restore the California waiver, although that court ruling has been appealed to the United States Supreme Court and is pending.

In 2022, California finalized the next generation of its GHG and ZEV standards (referred to as 'ACC II'). The ACC II sets annual ZEV and plug-in hybrid vehicle (PHEV) sales requirements from MY 2026 to 2035 and increasingly more stringent emission standards to ensure automakers gradually phase out new sales of internal combustion engine vehicles.

In 2023, California filed a CAA Section 209 waiver of federal pre-emption application with EPA. In December 2024, EPA granted California's waiver under ACC II that requires that by MY 2035, all new light-duty vehicles sold in California must be ZEVs or PHEVs. These regulations may impact bp's product mix and demand for particular products.

California Advanced Clean Trucks Program

In 2023, EPA granted California's request for a waiver of federal preemption covering, in part, its Advanced Clean Trucks Program, which mandates increasing quantities of ZEV sales for medium- and heavy-duty vehicles in the state. Legal challenges to that decision have been filed and are pending.

These and other initiatives to reduce GHG emissions may have a significant effect on the production, sale and profitability of many of bp's products in the US.

European Union

The EU has adopted a goal of achieving climate neutrality by 2050 as part of the European Green Deal and, subsequently, a 55% GHG reduction target by 2030 compared to 1990 levels. To achieve this target, EU member states and Parliament adopted most measures proposed as part of the so-called 'Fit for 55' package. These include: revisions of the EU Emissions Trading Scheme (EU ETS) and a newly created Carbon Border Adjustment Mechanism (CBAM); the Renewable Energy Directive (RED) – including an obligation on transport fuel suppliers to increase the share of renewables of their fuel supply; a sustainable aviation fuel (SAF) blending mandate from 2025; and CO_2 targets for the sales of new vehicles which are expected to accelerate the decarbonization of the transport sector and impact fuel demand.

Once fully adopted and implemented, this would inter alia lead to higher shares of renewables across all sectors (including transport), a reduced number of GHG emission allowances under the EU ETS, and a target of zero gramme of CO_2 per km for new passenger cars by 2035. The EU also adopted measures to reduce methane emissions.

Some EU member states have adopted national targets above and beyond current EU climate goals, such as Germany, with a climate neutrality target by 2045.

United Kingdom

In November 2024, the UK government announced a nationally determined contribution target to reduce all greenhouse gas emissions by at least 81% by 2035 compared to 1990 levels.

The UK Emissions Trading System (UK ETS) launched on 1 January 2021 following the end of the Brexit transition period and the UK's participation in the EU ETS. It seeks to provide a carbon pricing mechanism as a tool for helping achieve the UK's net zero target and covers the same GHGs and sectors as the EU ETS. bp's North Sea operations are subject to the UK ETS.

In July 2023, the UK government published a response to a 2022 consultation on proposed changes to the UK ETS rules. That response included decisions to expand the scope of the scheme to include domestic

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maritime transport from 2026, waste incineration and energy from waste from 2028 and process emissions from carbon dioxide venting from the upstream oil and gas sector from 2025.

In December 2023, the UK ETS Authority published two consultations. One covers a review of the UK ETS markets policy and the other relates to a review of free allocation methodology for the stationary sectors under the UK ETS to better target those most at risk of carbon leakage.

Other countries and regions

China is operating emissions trading pilot programmes in a number of cities and provinces. One of bp's subsidiaries in China is participating in these programmes. In February 2021 China introduced a national emissions trading market (National ETS). The National ETS is intended to be an essential tool for China to fulfil its commitment to reach peak emissions by 2030 and carbon neutrality by 2060. For now, the National ETS participants are limited to the key emission entities identified by each provincial-level government authority and approved by the Ministry for Ecology and Environment of China. bp is not participating in the National ETS. On 9 September 2024, the Ministry for Ecology and Environment of China released a draft work plan to expand the sectoral coverage of the National ETS. Currently covering only the power sector, the plan proposes to extend the National ETS to include the cement, steel, and aluminium industries.

In October 2021, as part of its ‘1+N’ climate policy framework, China issued working guidance setting out specific targets and measures for achieving peak carbon emissions and carbon neutrality, and an action plan which sets out the main objectives for the next decade to achieve peak carbon emissions by 2030. The working guidance is the '1' (i.e. a long-term approach to combating climate change), while 'N' are various policies starting with the action plan. In June 2022, 17 government authorities jointly released the National Climate Change Adaptation Strategy 2035 making overall plans to prepare the country to adapt to climate change from the present to 2035.

China's domestic voluntary carbon mechanism called the China Certified Emission Reduction (CCER) programme has been suspended since 2017. In 2023, significant progress towards relaunching the CCER has been made by relevant authorities, including the promulgation of a regulation on CCER trading for trial implementation and the publication of methodologies that will be used to quantify net emission reductions or removals for four types of projects (forestation, solar thermal power, offshore wind power generation and mangrove revegetation). CCER programme was relaunched on 22 January 2024 and the first CCER project after the relaunch was registered on 3 December 2024. On 3 January 2025, two new CCER methodologies were released – for issuing carbon credits to projects utilizing coal mine gas and energy efficient highway tunnel lighting.

On 5 January 2024, China’s State Council approved an interim regulation for the national emissions trading scheme. The final version was issued on 4 February 2024 which has provisions on defining the scale of the national carbon market, determining allocation of emissions allowances and data quality supervision.

Other environmental regulation

In addition to the GHG regulations referred to above, climate change programmes and regulation of unconventional oil and gas extraction under a number of environmental laws may have a significant effect on the production, sale and profitability of many of bp’s products.

Environmental laws also require bp to remediate and restore areas affected by the release of hazardous substances or hydrocarbons associated with our operations or properties. These laws may apply to sites that bp currently owns or operates, sites that it previously owned or operated, or sites used for the disposal of its and other parties’ waste. See Financial statements – Note 23 for information on provisions for environmental restoration and remediation.

A number of pending or anticipated governmental proceedings against certain bp group companies under environmental laws could result in monetary or other sanctions. Group companies are also subject to environmental claims for personal injury and property damage alleging the release of, or exposure to, hazardous substances. The costs associated with future environmental remediation obligations, governmental proceedings and claims could be significant and may be material to the results of operations in the period in which they are recognized. We cannot accurately predict the effects of future developments, such as stricter environmental laws and regulations or enforcement policies, or future events at our facilities on the group, and there can be no assurance that material liabilities and costs will not be incurred in the future. For a discussion of the group’s environmental expenditure, see page 329 and for a discussion of legal proceedings, see page 218.

Significant health, safety and environmental legislation and regulation affecting our businesses and profitability, in addition to those referred to above, include the following:

United States

- The Clean Water Act regulates wastewater and other effluent discharges from bp’s facilities, and bp is required to obtain discharge permits, install control equipment and implement operational controls and preventative measures.
- The Resource Conservation and Recovery Act (RCRA) regulates the generation, storage, transportation and disposal of wastes associated with our operations and can require corrective action at locations where such wastes have been disposed of or released. bp has incurred, or is likely to incur, liability under RCRA or similar state laws in connection with sites bp operates or previously operated.
- The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) can, in certain circumstances, impose the entire cost of investigation and remediation on a party who owned or operated a site contaminated with a hazardous substance, or who arranged for disposal of a hazardous substance at a site. bp has incurred, or is likely to incur, liability under CERCLA or similar state laws, including costs attributed to insolvent or unidentified parties. bp is also subject to claims for remediation costs and natural resource damages under CERCLA and other federal and state laws. CERCLA also requires reporting on the releases of certain quantities of listed hazardous substances to designated government agencies. In April 2024, EPA listed PFOA and PFOS (types of perfluoroalkyl substances (PFAS) used in fire-fighting foam and many consumer products) as hazardous substances under CERCLA. This listing may impact remediation costs and result in additional reporting and other environmental obligations. Several states have passed legislation limiting the use of PFAS in fire-fighting foam, and other states may do so in the future.
- The Emergency Planning and Community Right-to-Know Act requires reporting on the storage, use and releases of certain quantities of listed extremely hazardous substances to designated government agencies.
- The Toxic Substances Control Act regulates bp’s manufacture, import, export, sale and use of chemical substances and products. In addition, EPA has revised processes and procedures for prioritization of existing chemicals for risk evaluation, assessment and management. Agency actions and announcements are monitored regularly to identify developments with potential impacts on chemical substances important to bp products and operations.
- The Occupational Safety and Health Act imposes workplace safety and health requirements on bp operations along with significant process safety management obligations, requiring continuous evaluation and improvement of operational practices to enhance safety and reduce workplace emissions at gas processing, refining and other regulated facilities.
- The Oil Pollution Act 1990 imposes operational requirements, liability standards and other obligations governing the transportation of petroleum products in US waters. States may impose additional obligations. Alaska, West Coast and certain East Coast states impose additional requirements and stricter liability standards.
- The Outer Continental Shelf Land Act, the Mineral Leasing Act and other statutes give the Department of Interior (DOI) and the Bureau of Land Management authority to regulate operations and air emissions, including equipment and testing, at offshore and onshore operations on federal lands subject to DOI authority.
- The Endangered Species Act (ESA) and Marine Mammal Protection Act protect certain species’ habitats from adverse human impacts by restricting operations or development at certain times and in certain places. In 2020, the US Fish and Wildlife Service published regulatory definitions impacting habitat designations under the ESA, but in 2022 the Biden administration rescinded those definitions. The Biden administration rescission of those definitions could expand the geographic areas subject to habitat protections.

European Union

- The Industrial Emissions Directive (IED) 2010 provides the framework for granting permits for major industrial sites. A recently agreed revision of the IED could, once formally adopted and implemented, potentially set more stringent permitting requirements, and lead to a further tightening of emission limit values.
- The EU Registration, Evaluation Authorization and Restriction of Chemicals (REACH) Regulation 2006 requires registration of chemical substances manufactured in or imported into the EU, together with the submission of relevant hazard and risk data. REACH affects our manufacturing or trading/import operations in the EU. bp maintains compliance by checking whether imports are covered by the registrations of non-EU suppliers' representatives, preparing and submitting registration dossiers to cover new manufactured and imported substances, and updating previously submitted registrations as required.
- The Water Framework Directive (WFD) published in 2000 aims to protect the quantity and quality of ground and surface waters of the EU member states. The implementation in the EU member states is still ongoing, planned to be finalised by 2027. Future proceedings on the determination of pollutants/priority substances as well as environmental quality standards in line with the WFD may require additional compliance efforts and increased costs for managing freshwater withdrawals and discharges from bp's EU operations.
- The Corporate Sustainability Reporting Directive (CSRD) entered into force on 5 January 2023 introducing new requirements for certain EU and non-EU companies, to include disclosures related to climate, the environment and wider sustainability issues. The CSRD also expands to in-scope entities the requirements introduced by the EU Taxonomy Regulation, to identify environmentally sustainable activities and then disclose metrics related to capital and operating expenditure and turnover associated with those activities. Disclosure requirements will be phased in from 2025, in respect of the 2024 financial year.
- The Corporate Sustainability Due Diligence Directive (CSDDD) entered into force in July 2024 and requires certain EU and non-EU companies to conduct due diligence on human rights and environmental risks, adopt a transition plan aligned with the Paris Agreement, and comply with enforcement by EU authorities from July 2027.

United Kingdom

- Following the UK's exit from the European Union, operative EU laws were retained in UK law by the European Union (Withdrawal) Act 2018 (EUWA). In June 2023, the Retained EU Law (Revocation and Reform) Act 2023 received Royal Assent. That Act allows for significant changes to the status, operation and content of retained EU law, including through amendments to the EUWA. This may mean that over time there will be amendments to and deviations from retained EU law including in respect of environmental matters.
- Since the end of the transition period on 31 December 2020, there has been a parallel UK REACH regime which applies in Great Britain only, with EU REACH continuing to apply in Northern Ireland. UK REACH contains equivalent requirements to EU REACH, although future developments and potential divergences are uncertain.
- The Environment Act 2021 comprises various key parts including governance, waste and resource efficiency, air quality and environmental recall, water, nature and biodiversity and conservation covenants. The governance parts include a comprehensive framework for legally binding environmental improvement targets; to establish a framework for future policy statements on environmental principles to protect the environment by making environmental considerations a key part of policy development process across government; and to establish the Office for Environmental Protection, an independent public body to have oversight of environmental matters. The UK government's first suite of environmental targets became law in January 2023, but these have not had a material impact on bp.

Other countries and regions

Regulations governing the discharge of treated water have also been developed in countries outside the US and EU including in Trinidad where bp commissioned a new wastewater treatment plant in 2020 to meet consent levels agreed with the regulators to apply relevant water discharge rules.

The Abidjan Convention, along with the Additional Protocol published in 2012, sets environmental quality standards for the discharge of chemicals to the marine environment. Mauritania and Senegal are both signatories to the Abidjan Convention. bp is currently constructing the offshore facilities to include produced water management systems to meet the environmental quality standards for our future gas operations in Mauritania and Senegal.

The Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR), aims to protect the marine environment of the North-East Atlantic. The OSPAR 2012 recommendation and guideline for the implementation of a risk-based approach to the management of produced water discharges from offshore installations in the North Sea supports a key goal of working towards eliminating harmful discharges. In 2020 the International Association of Oil and Gas Producers issued a report 'Oil And Gas Risk Based Assessment of Offshore Produced Water Discharges' which presents industry good practice and aims to broaden the understanding and acceptance of Risk Based Assessment (RBA) techniques internationally and improve consistency in the application of assumptions, levels of conservatism, and selection of risk endpoints.

At OSPAR's Offshore Industry Committee (OIC) meeting in March 2024, the Committee agreed changes to OSPAR's List of Substances/Preparations Used and Discharged Offshore which are Considered to Pose Little or No Risk to the Environment (PLONOR). This includes two inorganic substances, calcium bromide and sodium bromide which are used in Completion fluid formulations. Further work is progressing on the harmonisation of OSPAR's approach to offshore chemicals and the REACH Regulation, now focused on the potential impact of adjustments to the current Harmonised Mandatory Control System (HCMS) for regulators and industry. OIC also agreed the report on the implementation of OSPAR Recommendation 2006/3 on Environmental Goals for the Discharge by the Offshore Industry of Chemicals that Are, or Which Contain Substances Identified as Candidates for Substitution – Technical and Safety Obstacles.

Environmental maritime regulations

bp's shipping operations are subject to extensive national and international regulations governing operations, training, pollution prevention, liability, and insurance. These include:

- Liability and spill prevention and planning requirements governing, among others, tankers, barges, and offshore facilities are imposed by OPA in US waters. OPA also mandates a levy on imported and domestically produced oil to fund oil spill responses. Some states, including Alaska, Washington, Oregon and California, impose additional liability for oil spills. Outside US territorial waters, bp shipping tankers are subject to international pollution prevention, liability, spill response and preparedness regulations developed through the UN's International Maritime Organization (IMO), including the International Convention on Civil Liability for Oil Pollution Damage, the International Convention for the Prevention of Pollution from Ships (MARPOL), the International Convention on Oil Pollution, Preparedness, Response and Co-operation, and the International Convention on Civil Liability for Bunker Oil Pollution Damage. In April 2010, the Hazardous and Noxious Substance (HNS) Protocol 2010 was adopted to address issues that have inhibited ratification of the International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea 1996. As at 31 December 2023, the HNS Convention had not entered into force.
- A global sulphur cap of 0.5% applies to marine fuel under MARPOL with a stricter 0.1% cap in environmentally sensitive areas. In order to comply, ships either need to consume low sulphur marine fuels, operate on alternative low sulphur fuels such as LNG or implement approved abatement technology to enable them to meet the low sulphur emissions requirements while continuing to use higher sulphur fuel. This global cap does not alter the lower 0.1% limits that apply in the sulphur oxides Emissions Control Areas established by the IMO.
- From 2023 all vessels over 400 gross tonnage became subject to IMO requirements as to energy efficiency design (EEXI) and the carbon intensity of operations (CII).
- Under EU legislation, maritime transport has been brought into the scope of the EU ETS from 2024, applicable to all vessels over 5,000 gross tonnage calling at EU ports regardless of a vessel's flag.

- Under the Fuel EU Maritime Regulation, from 2025 ship owners are required to reduce the GHG intensity of their fuel use gradually over time, initially by 2% by 2030 and 80% by 2050.
- From 2025 tankers calling at California's major ports must comply with emission reduction and reporting requirements set by the California Air Resources Board (CARB), aimed at limiting emission of pollutants including oxides of nitrogen (Nox) and diesel particulate matter.

To meet its financial responsibility requirements, bp shipping maintains marine oil pollution liability insurance in respect of its operated ships to a maximum limit of $1 billion for each occurrence through mutual insurance associations (P&I Clubs), although there can be no assurance that a spill would necessarily be adequately covered by insurance or that liabilities would not exceed insurance recoveries.

International trade sanctions

During the period covered by this report, non-US subsidiaries, or other non-US entities of bp, conducted limited activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of Terrorism or otherwise subject to US, EU and UK sanctions (Sanctioned Countries). In 2024, sanctions restrictions were insignificant to the group's financial condition and results of operations. bp monitors its activities with Sanctioned Countries, persons from Sanctioned Countries and individuals and companies subject to US, EU and UK sanctions and seeks to comply with applicable sanctions laws and regulations.

bp has a 29.99% interest in and operates the Shah Deniz field in Azerbaijan (Shah Deniz), has a 29.99% interest in and performs some operations for a related gas pipeline entity, South Caucasus Pipeline Company Limited (SCPC), and has a 23.99% non-operating interest in a related gas marketing entity, Azerbaijan Gas Supply Company Limited (AGSC). Naftiran Intertrade Co. Limited and NICO SPV Limited (collectively, NICO) have a 10% non-operating interest in each of Shah Deniz and SCPC and an 8% non-operating interest in AGSC. Shah Deniz, SCPC and AGSC continue in operation as they were excluded from the application of US sanctions and fall within the exception for certain natural gas projects under Section 603 of the Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA).

On 3 December 2018 bp entered into an agreement with, among others, SOCAR and NICO pursuant to which SOCAR pays to BP Exploration (Shah Deniz) Limited (BPXSD), as the Shah Deniz operator, compensation for NICO's waiver of its right to lift its share of Shah Deniz condensate. Such amounts are used to cover cash calls to NICO in respect of operating costs due from NICO to BPXSD. OFAC has issued a licence in relation to these arrangements which expires on 15 April 2026.

Following the imposition in 2011 of further US and EU sanctions against Syria, bp terminated all sales of crude oil and petroleum products into Syria, though bp continues to supply aviation fuel to non-governmental Syrian resellers outside of Syria.

bp has a joint arrangement in Cuba which imports, manufactures, markets and sells lubricants.

Since 2014, the US and the EU have imposed sanctions on certain sectors of the Russian economy (energy, finance and defence/military) and on certain individuals and entities, including Rosneft. These sectoral sanctions include restrictions on certain oil and gas activities in Russia including the provision of financial assistance, technical assistance, goods and services.

In response to Russia's military action in Ukraine in 2022, the US, EU, UK and many other countries have imposed broad economic and trade sanctions. The scope of these sanctions includes restrictions on dealing with designated individuals and entities; restrictions on the Russian financial sector; blocking economic activity in certain areas of Ukraine not controlled by the Ukrainian government; prohibitions in relation to investment in Russia; prohibitions and restrictions relating to Russian origin oil and oil products; prohibitions and restrictions relating to Russian origin iron and steel products, prohibitions and restrictions relating to Russian origin metals, prohibitions and restrictions on the provision of certain legal advisory services, prohibitions and restrictions in relation to transportation, including shipping and aircraft; trade controls limiting the purchase and import of a wide range of goods from Russia, and export controls limiting the export of a wide range of goods and technical assistance to Russia.

In response, Russia has implemented counter-sanctions including restrictions on the divestment from Russian assets by foreign investors and 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.

The bp group does not source any materials directly from Russia, except deliveries of LNG from Russian sources under a small number of contracts predating the Russia and Ukraine conflict in compliance with all applicable sanctions. bp has also discontinued sales of our products to customers in Russia. Such sales were not material to the bp group. As a result, outside of our shareholding in Rosneft and related businesses in Russia, direct impacts due to exposure to Russia have not been material and are not expected to be material in the future. bp continues to monitor Russia related sanctions and other international restrictions for any impacts on our businesses and the exit of our shareholding in Rosneft. See page 173 for further information in relation to bp's shareholding in Rosneft.

bp maintains bank accounts and has registered and paid required fees to maintain registrations of patents and trademarks in certain Sanctioned Countries.

bp has equity interests in non-operated joint arrangements with air fuel sellers, resellers, and fuel delivery services around the world. From time to time, the joint arrangement operator or other partners may sell or deliver fuel to airlines from Sanctioned Countries or flights to Sanctioned Countries, without bp's involvement.

bp has no control over the activities non-controlled associates may undertake in Sanctioned Countries or with persons from Sanctioned Countries.

Disclosure pursuant to ITRA Section 219

To our knowledge, none of bp's activities, transactions or dealings are required to be disclosed pursuant to ITRA Section 219, with the following possible exceptions.

In 2024, payments in relation to tax with an aggregate US dollar equivalent value of approximately $3,000 were made from a bp trust account held with Tadvin Co. to Iranian public entities on behalf of BP Iran. No gross revenues or net profits are attributable to BP Iran's activities.

Material contracts

On 4 April 2016 the district court approved the Consent Decree among BP Exploration & Production Inc., BP Corporation North America Inc., BP p.l.c., the United States and the states of Alabama, Florida, Louisiana, Mississippi and Texas (the Gulf states) which fully and finally resolved any and all natural resource damages (NRD) claims of the United States, the Gulf states, and their respective natural resource trustees and all Clean Water Act (CWA) penalty claims, and certain other claims of the United States and the Gulf states.

Concurrently, the definitive Settlement Agreement that bp entered into with the Gulf states (Settlement Agreement) with respect to State claims for economic, property and other losses became effective.

bp has filed the Consent Decree and the Settlement Agreement as exhibits to its Annual Report and Form 20-F 2020 filed with the SEC. For further details of the Consent Decree and the Settlement Agreement, see Legal proceedings in bp Annual Report and Form 20-F 2015.

Property, plant and equipment

bp has freehold and leasehold interests in real estate and other tangible assets in numerous countries, but no individual property is significant to the group as a whole. For more on the significant subsidiaries★of the group at 31 December 2024 and the group percentage of ordinary share capital see Financial statements – Note 37. For information on significant joint ventures★ and associates★of the group see Financial statements – Notes 16 and 17.

Related party transactions

Transactions between the group and its significant joint ventures and associates are summarized in Financial statements – Note 16 and Note 17. In the ordinary course of its business, the group enters into transactions with various organizations with which some of its directors or executive officers are associated. Except as described in this report, the group did not have any material transactions or transactions of an unusual nature with, and did not make loans to, related parties in the period commencing 1 January 2024 to 14 February 2025.

Corporate governance practices

In the US, bp ADSs are listed on the New York Stock Exchange (NYSE). The significant differences between bp's corporate governance practices as a UK company and those required by NYSE listing standards for US companies are listed as follows:

Independence

As set out on page 75, bp has adopted separate terms of reference for the board and each of its committees as part of its corporate governance framework. The terms of reference for the board and each of its committees are reviewed at least annually. The board and audit committee terms of reference were last updated with effect from 1 January 2025, while the other three principal committees were last updated with effect from 25 July 2024. The terms of reference reflect the UK Corporate Governance Code approach to corporate governance. As such, the way in which bp makes determinations of directors' independence differs from the NYSE approach.

bp's corporate governance framework requires that all non-executive directors (NEDs) be determined by the board to be 'independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement'. The bp board has determined that, in its judgement, all of the NEDs are independent. In doing so, however, the board did not explicitly take into consideration the independence requirements outlined in the NYSE's listing standards.

Committees

bp has a number of board committees that are broadly comparable in purpose and composition to those required by NYSE rules for domestic US companies. For instance, bp has a remuneration (rather than a compensation) committee. bp also has an audit committee, which NYSE rules require for both US companies and foreign private issuers. These committees are composed solely of NEDs whom the board has determined to be independent, in the manner described above.

Each committee operates under its own terms of reference together with a set of terms applicable to all the committees (see the board committee reports on pages 80-110 and bp.com/governance).

Under US securities law and the listing standards of the NYSE, bp is required to have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act and Section 303A.06 of the NYSE Listed Company Manual. bp's audit committee complies with these requirements. The bp audit committee does not have direct responsibility for the appointment, reappointment or removal of the independent auditors. Instead, it follows the UK Companies Act 2006 and the UK Corporate Governance Code by making recommendations to the board on these matters for it to put forward for shareholder approval at the AGM.

One of the NYSE's additional requirements for the audit committee states that at least one member of the audit committee is to have 'accounting or related financial management expertise'. The board determined that Tushar Morzaria possesses such expertise and also possesses the financial and audit committee experience set forth in both the UK Corporate Governance Code and the SEC rules (see audit committee report on page 82). Mr Morzaria is the audit committee financial expert as defined in Item 16A of Form 20-F.

Summary of terms of reference for audit committee and remuneration committee

The audit committee's full terms of reference are available on our website at bp.com/governance. A summary of the committee's key responsibilities is provided below:

- Monitor and critically assess bp's financial statements and financial information, including the integrity of the financial reporting and related processes, context in which statements are made, compliance with relevant legal and regulatory requirements and financial reporting standards, including the Task Force on Climate-related Financial Disclosures (TCFD).
- Assess the going concern assumption and the longer-term viability statement as to bp's ability to continue to operate and meet its liabilities.
- Review and challenge the application and appropriateness of significant accounting policies and financial reporting estimates and judgements.
- Evaluate the risk to quality and effectiveness of the financial reporting process and, where requested by the board, advise whether the Annual Report and accounts are fair, balanced and understandable.
- Review the affordability of distributions to shareholders.
- Oversee the appointment, remuneration, independence and performance of the external auditor and the integrity of the audit process as a whole, including the engagement of the external auditor to supply non-audit services to bp.
- Review the effectiveness of the internal audit function, bp's internal financial controls and its systems of internal control and risk management.
- Monitor the principal risks allocated to the committee by the board and review the mitigations proposed by management in respect of risks associated with bp internal financial controls and reporting responsibilities and such emerging risks that may fall within scope.
- Review the systems in place to enable those who work for bp to raise concerns about improprieties in financial reporting or other issues, and for those matters to be investigated.

The remuneration committee's full terms of reference are available on our website at bp.com/governance. A summary of the committee's key responsibilities is provided below:

- Recommend to the board the remuneration principles for the executive directors while considering remuneration and related policies for the employees below the board and leadership team.
- Set and approve the terms of appointment, fees and benefits for the chair of the board in accordance with the policy.
- Set and approve the terms of engagement, remuneration, benefits and termination of employment for the executive directors, leadership team, chief internal auditor, head of ethics and compliance and the company secretary in accordance with the policy.
- Prepare the annual remuneration report to shareholders to outline policy implementation.
- Approve the principles of any equity plan that requires shareholder approval.
- Ensure termination terms and payments to executive directors and the leadership team are appropriate and fair.
- Receive and consider regular updates on workforce views and engagement initiatives related to remuneration, insights and data from pay ratios and potential pay gaps as appropriate.
- Maintain appropriate dialogue with shareholders on remuneration matters.

Shareholder approval of equity compensation plans

The NYSE rules for US companies require that shareholders must be given the opportunity to vote on all equity-compensation plans and material revisions to those plans. bp complies with UK requirements that are similar to the NYSE rules. The board, however, does not explicitly take into consideration the NYSE's detailed definition of what are considered 'material revisions'.

Item 16J insider trading policy

The board has approved a share dealing policy governing the acquisition, sale and other dispositions of the company's securities by employees, contractors, officers and members of the board of the company.

The bp share dealing policy is included in this Form 20-F as Exhibit 11.2.

Code of ethics

The company has adopted a code of ethics for its chief executive officer, chief financial officer, SVP accounting, reporting and control and SVP internal audit whose roles are equivalent to the SEC roles as required by the provisions of Section 406 of the Sarbanes-Oxley Act of 2002 and the rules issued by the SEC. There have been no waivers from the code of ethics relating to any officers. A copy of the code of ethics can be found at bp.com/codeofethics.

★ See glossary on **page 351**

The NYSE rules require that US companies adopt and disclose a code of business conduct and ethics for directors, officers and employees. bp has adopted a code of conduct, which applies to all employees, officers and members of the board. This was updated and published in January 2023, with certain elements further updated and published in June 2024. In addition, bp has adopted a code of ethics as described above for the chief executive officer, chief financial officer, SVP accounting, reporting and control and SVP internal audit as required by the SEC. bp considers that these codes and policies address the matters specified in the NYSE rules for US companies. During 2021, the board adopted a diversity policy, which requires it to encourage a diverse and inclusive working environment in the boardroom. The policy was most recently reviewed by the board in 2024, and amendments were made to reflect regulatory changes and market practice. The updated policy was then approved with effect from 1 January 2025.

Controls and procedures

Evaluation of disclosure controls and procedures

The company maintains 'disclosure controls and procedures', as such term is defined in Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including the company's group chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, our management, including the group chief executive and chief financial officer, recognize that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud within the company, if any, have been detected. Further, in the design and evaluation of our disclosure controls and procedures our management necessarily was required to apply its judgement in evaluating the costs and benefits of possible control and procedure design options. Also, we have investments in unconsolidated entities. As we do not control these entities, our disclosure controls and procedures with respect to such entities are necessarily substantially more limited than those we maintain with respect to our consolidated subsidiaries★. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. The company's disclosure controls and procedures have been designed to meet, and management believes that they meet, reasonable assurance standards.

The company's management, with the participation of the company's group chief executive and chief financial officer, has evaluated the effectiveness of the company's disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the group chief executive and chief financial officer have concluded that the company's disclosure controls and procedures were effective at a reasonable assurance level.

Management's report on internal control over financial reporting

Management of bp is responsible for establishing and maintaining adequate internal control over financial reporting. bp's internal control over financial reporting is a process designed under the supervision of the principal executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of bp's financial statements for external reporting purposes in accordance with IFRS.

As of the end of the 2024 fiscal year, management conducted an assessment of the effectiveness of internal control over financial reporting in accordance with the criteria in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting relating to internal control over financial reporting.

Based on this assessment, management has determined that bp's internal control over financial reporting as of 31 December 2024 was effective.

Management's assessment of the effectiveness of internal control over financial reporting excluded bp bioenergy (formerly called bp Bunge Bioenergia) and Lightsource bp which were acquired on 1 October 2024, and 24 October 2024, respectively. bp bioenergy's financial statement line items comprise 2.1% and 0.9% of net and total assets respectively, 0.3% of sales and other operating revenues, and (4.5)% of profit (loss) for the year of the consolidated financial statement amounts as of and for the year ended 31 December 2024. Lightsource bp's financial statement line items comprise 6.3% and 2.4% of net and total assets respectively, 0.1% of sales and other operating revenues, and (5.7)% of profit (loss) for the year of the consolidated financial statement amounts as of and for the year ended 31 December 2024. These exclusions are in accordance with the general guidance issued by the SEC that an assessment of a recent business combination may be omitted from managements report on internal control over financial reporting in the first year of consolidation.

The company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of bp; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of bp's assets that could have a material effect on our financial statements. bp's internal control over financial reporting as of 31 December 2024 has been audited by Deloitte LLP, an independent registered public accounting firm, as stated in their report appearing on page 139 of bp Annual Report and Form 20-F 2024.

Changes in internal control over financial reporting

There were no changes in the group's internal control over financial reporting that occurred during the period covered by the Form 20-F that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Cyber security

Governance

The board oversees bp's internal control and risk management framework. The board is supported by the safety and sustainability committee which oversees cyber security risk and received reports from bp's chief information security officer (CISO) on cyber security incidents at every committee meeting in 2024, including information on bp's response to incidents. This allows an ongoing assessment by the committee of the effectiveness of bp's overall cyber security programme. A session is held once a year to review bp's roadmap and progress for addressing cyber security risk. Read more in the safety and sustainability committee report on page 80.

At management level, assessment and management of material risks from cyber security threats is led by bp's executive vice president of technology, a member of bp's leadership team with deep experience in bp's engineering and operations functions, with support from bp's CISO, who has over 20 years of experience in the information technology industry. bp's digital safety operational risk committee brings together additional senior members of bp's digital leadership team to assist in ensuring that cyber security risks across bp are identified, understood, accurately quantified and are managed in accordance with bp's internal controls framework.

Risk management and strategy

bp has implemented a threat-focused strategy to assess cyber security risks and protect against, detect, respond to, and recover from cyber attacks. bp maintains internal teams focused on cyber security intelligence and emergency response to monitor the external threat landscape and the threats to bp's IT and operational technology infrastructure. bp partners with third-party specialists to augment its in-house capabilities as necessary. bp has a defined protocol for cyber incident notification based on severity and bp's internal cyber security teams brief the CISO, technology EVP, other senior leadership and relevant board and management committees about incidents on an as needed basis.

Cyber security risk management is integrated into bp's overall risk management process. bp's entities are required to identify, assess and report key risks, including cyber security risks, to relevant members of senior leadership. bp maintains additional procedures to manage cyber security risks related to third-party service providers, including conducting information security assessments for certain providers, providing relevant trainings for bp employees, and maintaining information security requirements for suppliers.

Our business strategy, results of operations and financial condition have not been materially affected by risks from cyber security threats, including as a result of previously identified cyber security incidents. For more information on our cyber security related risks, see Risk Factors (pages 79-67).

Principal accountant's fees and services

The audit committee has established policies and procedures for the engagement of the independent registered public accounting firm, Deloitte LLP, to render audit and certain assurance services. The policy provides for pre-approval by the audit committee of specifically defined audit, audit related, non-audit and other services that are not prohibited by regulatory or other professional requirements. Deloitte is engaged for these services when its expertise and experience of bp are important. Most of this work is of an audit nature.The audit committee, CFO and SVP accounting, reporting and control, monitor overall compliance with bp's policy on audit-related and non-audit services, including whether the necessary pre-approvals have been obtained. The committee regularly reviews the policy, including in 2022, when it was updated to remove restrictions on EY following bp's announcement on 27 February 2022 of its intention to exit its interests in Rosneft and capture additional detail for the processes applicable to separately listed bp entities.

Under the policy, pre-approval is given for specific services within the following categories: i) audit-related services, such as those required by law or where the auditor is best placed to undertake such work on similar terms, ii) non-audit services required by law, such as reporting required by a regulatory authority, and iii) other services, such as additional assurance or updates on applicable law and accounting standards. bp operates a two-tier system for audit and non-audit services. For audit-related services, the audit committee has a pre-approved aggregate level, within which specific work may be approved by management. Non-audit services are pre-approved for management to authorize per individual engagement, but above a defined level must be approved by the chair of the audit committee or the full committee. The audit committee has delegated to the chair of the audit committee authority to approve permitted services provided that any decisions are reported to the committee at its next scheduled meeting. Any proposed service not included in the approved service list must be approved in advance of commencing the engagement by the audit committee chair or the full audit committee depending on the level of fee payable.

The audit committee evaluates the performance of the auditor each year. The audit fees payable to Deloitte are reviewed by the committee in the context of other global companies for cost effectiveness. The committee keeps under review the scope and results of audit work and the independence and objectivity of the auditor. External regulation and bp policy requires the auditor to rotate its lead audit partner every five years. See Financial statements – Note 36 and audit committee report on page 82 for details of fees for services provided by the auditor.

Additional Directors' report disclosures

This section of bp Annual Report and Form 20-F 2024 forms part of the Directors' report. Certain information has been included in the Strategic report that would otherwise be required to be disclosed in the Directors' report, as noted below.

Indemnity provisions

In accordance with bp's Articles of Association, on appointment each director is granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report. In respect of those liabilities for which directors may not be indemnified, the company maintained a directors' and officers' liability insurance policy throughout 2024. During the year, a review of the terms and scope of the policy was undertaken as part of the annual renewal. Although their defence costs may be met, neither the company's indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly. One of the group's subsidiaries★ is a trustee of the UK pension scheme. Each director of that subsidiary is granted an indemnity from the company in respect of liabilities incurred as a result of such a subsidiary's activities as a trustee of the pension scheme, to the extent permitted by law. These indemnities were in force throughout the financial year and as at the date of this report.

Financial risk management objectives and policies

The disclosures in relation to financial risk management objectives and policies, including the policy for hedging, are included in How we manage risk on page 61, Liquidity and capital resources on page 316 and Financial statements – Notes 29 and 30.

Exposure to price risk, credit risk, liquidity risk and cash flow risk

The disclosures in relation to exposure to price risk, credit risk, liquidity risk and cash flow risk are included in Financial statements – Notes 29 and 30.

Important events since the end of the financial year

Disclosures of the particulars of the important events affecting bp which have occurred since the end of the financial year are included in the Strategic report as well as in other places in the Directors' report.

Likely future developments in the business

An indication of the likely future developments in the business of the company is included in the Strategic report.

Research and development

Indications of our activities in the field of research and development are provided throughout the Strategic report and the Directors' report. See also pages 12 and 171 for our expenditure on research and development.

Branches

As a global group our interests and activities are held or operated through subsidiaries, branches, joint arrangements★ or associates★ established in – and subject to the laws and regulations of – many different jurisdictions.

Employees

Disclosures in respect of how the directors have engaged with employees and had regard to their interests are included in our stakeholders and key decisions on pages 77, 78 and 79.

The disclosures concerning policies in relation to the employment of disabled persons and employee involvement are included in Sustainability – our people on page 58.

Employee share schemes

Certain shares held as a result of participation in some employee share plans carry voting rights. Voting rights in respect of such shares are exercisable via a nominee. Dividend waivers are in place in respect of unallocated shares held in employee share plan trusts.

Suppliers, customers and others

Disclosures in respect of how the directors have engaged with suppliers, customers and others in business relationships with the company are included in our stakeholders on pages 78 and 79.

Change of control provisions

On 5 October 2015, the United States lodged with the district court in MDL 2179 a proposed Consent Decree between the United States, the Gulf states, BP Exploration & Production Inc., BP Corporation North America Inc. and BP p.l.c., to fully and finally resolve any and all natural resource damages claims of the United States, the Gulf states and their respective

★ See glossary on **page 351**

natural resource trustees and all Clean Water Act penalty claims, and certain other claims of the United States and the Gulf states. Concurrently, bp entered into a definitive Settlement Agreement with the five Gulf states (Settlement Agreement) with respect to state claims for economic, property and other losses. On 4 April 2016, the district court approved the Consent Decree, at which time the Consent Decree and Settlement Agreement became effective. The federal government and the Gulf states may jointly elect to accelerate the payments under the Consent Decree in the event of a change of control or insolvency of BP p.l.c., and the Gulf states individually have similar acceleration rights under the Settlement Agreement. For further details of the Consent Decree and the Settlement Agreement, see Legal proceedings in bp Annual Report and Form 20-F 2015.

Political donations, expenditure and contributions

Disclosures in relation to political donations, expenditure and contributions are included on page 59.

Greenhouse gas emissions, energy consumption and energy efficiency

Disclosures in relation to greenhouse gas emissions, energy consumption and energy efficiency are included in Sustainability on pages 40-41.

Disclosures required under UK Listing Rule 6.6.1R

The information required to be disclosed by UK Listing Rule 6.6.1R can be located as set out below:

Information required	Page
(1) Amount of interest capitalized	171
(2), (3)	Not applicable
(4), (5) Waiver of director emoluments	Not applicable
(6) – (10)	Not applicable
(11), (12) Dividend waivers	337
(13)	Not applicable

Cautionary statement

In order to utilize the 'safe harbor' provisions of the United States Private Securities Litigation Reform Act of 1995 (the 'PSLRA') and the general doctrine of cautionary statements, bp is providing the following cautionary statement.

This document contains certain forecasts, projections and forward-looking statements - that is, statements related to future, not past, events and circumstances - with respect to the financial condition, results of operations and businesses of bp and certain of the plans and objectives of bp with respect to these items. These statements may generally, but not always, be identified by the use of words such as 'will', 'expects', 'is expected to', 'aims', 'should', 'may', 'objective', 'is likely to', 'intends', 'believes', 'anticipates', 'plans', 'we see' or similar expressions. In particular, among other statements, (i) certain statements in the Chair's letter (page 4), Chief executive officer's letter (page 5),the Strategic report (inside cover and pages 1-68), Additional disclosures (pages 311-339) and Shareholder information (pages 341-350),including but not limited to statements under the headings 'Energy Outlook', 'Our strategy', 'Consistency with the Paris goals', 'Our business model', 'Our financial frame', '2025 guidance' 'Outlook for 2025', 'Our investment process' and '2025 shareholder calendar' and including but not limited to statements regarding: plans and expectations relating to business, financial performance, results of operations, cash flow, allocation of capital expenditure and bp's ability to maintain a robust cash position; plans and expectations regarding bp's financial frame (including annual dividend increases, net debt, credit rating, capital expenditures and distribution of operating cash flow as dividends and share buybacks), working capital, operating cash flow (and its ability to cover capital expenditure and the dividend), return on average capital employed, liquidity, capital discipline, credit rating, future shareholder distributions including future dividend payments and share buybacks, amount or timing of payments related to divestments and other proceeds, net debt, use of proceeds and progress towards our cost saving targets; plans and expectations regarding bp's 2025 targets, 2025 guidance (including with respect to reported and underlying upstream production, total capital expenditure, depreciation, depletion and amortization, divestments and other proceeds, Gulf of America oil spill payments, other businesses & corporate underlying annual charge, and the effective tax rate and the underlying effective tax rate), 2030 aims, 2050 or sooner net zero aims; plan and expectations regarding bp's engagement plans and programs and their impact on bp's ability to meet its aims, targets and strategic objectives; plans and expectations regarding bp's primary targets (including adjusted free cash flow growth, group ROACE, structural cost reduction, net debt) and reporting of bp's progress towards those targets; plans and expectations regarding the impact on underlying performance of bp's comprehensive February update; plans and expectations for growth in bp's customers businesses, products refining margins, underlying performance, improvement plans, refinery turnaround activity plans and expectations regarding interest rate reductions during 2025; plans and expectations relating to bp's investment process, strategy and capital investment, including future capital investment allocation, expected IRR, access to capital and the restructuring of certain investments; plans and expectations relating to bp's intra-group funding and liquidity arrangements; plans and expectations relating to bp's ability to meet contractual obligations; expectations regarding inflation, price volatility, refining margins and price assumptions; plans and expectations relating to risk, including risk management processes and climate-related risks; plans, expectations and projections regarding bp's oil and gas business, including related investment plans and their impact on production and cash flow, oil and gas prices, oil and gas production targets, growth in underlying production, divestment plans, and oil and gas resources and reserves; plans and expectations regarding underlying replacement cost profit before interest, tax, depreciation and amortization, ROACE, adjusted EBITDA and adjusted EBIDA per share; plans and expectations regarding bp's convenience and mobility business, including earnings and the development of EV charging; plans and expectations regarding bp's ability to make focused high-return investments in aviation and their impact; plans and expectations for the timing of bp's energy efficiency reviews and their outcomes; plans and expectations regarding renewable power, including plans regarding renewable gas, wind and solar projects, green and blue hydrogen costs and production and EV charging; plans and expectations regarding carbon capture and storage; plans and expectations regarding bp's investments in resilient hydrocarbons; bp's plans and expectations related to the energy transition (including its scenario analysis), climate change, sustainability (including bp's sustainability aims), greenhouse gas emissions, and management, decarbonization, and net zero aims; plans and expectations regarding bp's focus on biodiversity and water use, including bp's freshwater use, bp's freshwater management approach, bp's ability to address water-related business risk and bp's freshwater withdrawal in stressed catchments; plans and expectations regarding projects, joint ventures, partnerships, agreements and memoranda of understanding with governments, commercial entities and other third party partners (including, but not limited to, JERA Nex bp, the Northern Endurance Partnership projects, the Arcius Energy joint venture, the new ADNOC-operated LNG facility in Abu Dhabi, the long-term LNG supply agreement with KOGAS, the Kaskida project, the Coconut gas development, the Tangguh UCC project, the Northern Endurance Partnership, Net Zero Teesside Power, Cypre, the Tyrving development, projects in the North Sea and Norwegian Sea, the Lingen Green Hydrogen project, the Atlantis Drill Center Expansion, bp's Castellón refinery, the Kirkuk project, the deal with Simon Property Group, the Greater Tortue Ahmeyim project, the North West Shelf project and the Mento platform); plans and expectations regarding the timing of the sale of bp's mobility and convenience and bp pulse businesses in the Netherlands and bp Wind Energy; plans regarding transformation of the Gelsenkirchen refinery site; plans and expectations in relation to the strategic review of Castrol; plans and expectations in relation to Lightsource bp; expectations regarding contingent liabilities, legal and trial proceedings, court decisions, potential investigations and civil actions by regulators, government entities and/or other entities or parties, and the timing and potential impact of such proceedings, settlement agreements relating to such proceedings and bp's intentions in respect thereof; plans and expectations regarding relationships with governments, customers, partners, suppliers, communities and key stakeholders; plans and expectations regarding upstream production and downstream performance, expected improved downstream performance and returns; plans and expectations regarding the growth of bp's European gas and power presence; plans and expectations regarding operations and safety; expectations regarding the structure of energy demand; plans and expectations regarding the competitiveness and value of bp's refineries; plans and expectations relating to bp's research and development spend and outcomes; plans and expectations relating to a re-tender of external audit services; expectations related to changes laws, regulations and policies; plans and expectations regarding bp's shareholder calendar; and plans regarding seismic reprocessing activity.

By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of bp.

Actual results or outcomes may differ materially from those expressed in such statements, depending on a variety of factors, including: the extent and duration of the impact of current market conditions including the volatility of oil prices, the effects of bp's plan to exit its shareholding in Rosneft and other investments in Russia, overall global economic and business conditions impacting bp's business and demand for bp's products as well as the specific factors identified in the discussions accompanying such forward-looking statements; changes in consumer preferences and societal expectations; the pace of development and adoption of alternative energy solutions; developments in policy, law, regulation, technology and markets, including societal and investor sentiment related to the issue of climate change; the receipt of relevant third party and/or regulatory approvals including ongoing approvals required for the continued developments of approved projects; the timing and level of maintenance and/or turnaround activity; the timing and volume of refinery additions and outages; the timing of bringing new fields onstream; the timing, quantum and nature of certain acquisitions and divestments; future levels of industry product supply, demand and pricing, including supply growth in North America and continued base oil and additive supply shortages; OPEC+ quota restrictions; PSA and TSC effects; operational and safety problems; potential lapses in product quality; economic and financial market conditions generally or in various countries and regions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations and policies, including related to climate change; changes in social attitudes and customer preferences; regulatory or legal actions including the types of enforcement action pursued and the nature of remedies sought or imposed; the actions of prosecutors, regulatory authorities and courts; delays in the processes for resolving claims; amounts ultimately payable and timing of payments relating to the Gulf of America oil spill; exchange rate fluctuations; development and use of new technology; recruitment and retention of a skilled workforce; the success or otherwise of partnering; the actions of competitors, trading partners, contractors, subcontractors, creditors, rating agencies and others; bp's access to future credit resources; business disruption and crisis management; the impact on bp's reputation of ethical misconduct and non-compliance with regulatory obligations; trading losses; major uninsured losses; the possibility that international sanctions or other steps taken by governmental or any other relevant persons may impact bp's ability to sell its interests in Rosneft, or the price for which bp could sell such interests; the actions of contractors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism; cyber-attacks or sabotage; and those factors discussed elsewhere in this report including under Risk factors (page 65). In addition to factors set forth elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Statements regarding competitive position

Statements referring to bp's competitive position are based on the company's belief and, in some cases, rely on a range of sources, including investment analysts' reports, independent market studies and bp's internal assessments of the relevant market based on publicly available information about the financial results and performance of market participants.

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Shareholder information

Share prices and listings

Markets and market prices

The primary market for the company's ordinary shares (trading symbol 'BP'), 8% cumulative first preference shares (trading symbol 'BP.A') and 9% cumulative second preference shares (trading symbol 'BP.B') is the London Stock Exchange (LSE). The company's ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index.

In the US, the company's securities are listed and traded on the New York Stock Exchange (NYSE) in the form of ADSs (trading symbol 'BP'), for which JPMorgan Chase Bank, N.A. is the depositary (the Depositary) and transfer agent. The Depositary's principal office is 383 Madison Avenue, Floor 11, New York, NY, 10179, US. Each ADS represents six ordinary shares. ADSs are evidenced by American depositary receipts (ADRs), which may be issued in either certificated or book entry form.

The company's ordinary shares are also traded in the form of a global depositary certificate representing the company's ordinary shares on the Frankfurt Stock Exchange. The company delisted from the Hamburg and Düsseldorf Stock Exchanges on 20 December 2024 and announced its intention to delist from the Frankfurt Stock Exchange on 18 April 2024.

On 14 February 2025, 698,589,844 ADSs (equivalent to approximately 4,191,539,064 ordinary shares or some 26.19% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 58,929 ADS holders. Of these, about 58,209 had registered addresses in the US at that date. One of the registered holders of ADSs represents approximately 1,371,412 underlying holders.

On 14 February 2025, there were approximately 192,951 ordinary shareholders. Of these shareholders, around 1,464 had registered addresses in the US and held a total of some 3,840,494 ordinary shares. On 14 February 2025, there were approximately 1,074 preference shareholders. Of these shareholders, around 14 had registered addresses in the US and held a total of some 2,773 preference shares.

Since a number of the ordinary shares and ADSs were held by brokers and other nominees, the number of holders in the US may not be representative of the number of beneficial holders or their respective country of residence.

Dividends

The company's current policy is to pay interim dividends on a quarterly basis on its ordinary shares.

Our policy is also to announce dividends for ordinary shares in US dollars and state an equivalent sterling dividend. Dividends on the company's ordinary shares will be paid in sterling and on the company's ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the market exchange rates in London over the three business days prior to the sterling equivalent announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced. It is not the company's intention to change its current policy of announcing dividends on ordinary shares in US dollars.

Information regarding dividends announced and paid by the company on ordinary shares and preference shares is provided in the consolidated Financial statements – Note 10.

A Scrip Dividend Programme (Scrip Programme) was approved by shareholders in 2010 and was renewed for a further three years at the 2021 AGM. It enabled the company's ordinary shareholders and ADS holders to elect to receive dividends by way of new fully paid ordinary shares (or ADSs in the case of ADS holders) instead of cash. The operation of the Scrip Programme is always subject to the directors' decision to make the Scrip Programme offer available in respect of any particular dividend.

The company announced on 29 October 2019 and as part of all subsequent quarterly results announcements made since, that the board had suspended the Scrip Programme in respect of those quarterly dividends. The company does not expect to offer a scrip election for the foreseeable future. Ordinary shareholders and ADS holders (subject to certain exceptions) may be able to participate in dividend reinvestment plans. Any decisions with respect to future dividends will be made by the board of BP p.l.c. following the end of each quarter.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on page 65 and other matters that may affect the business of the group set out in Our strategy on page 8 and in Liquidity and capital resources on page 316.

The quarterly dividend which is expected to be paid on 28 March 2025 in respect of the fourth quarter 2024 is 8.000 cents per ordinary share ($0.48000 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 17 March 2025.

The following table shows dividends announced and paid by the company per ADS for the past five years.

Dividends per ADS[a]		March	June	September	December	Total
2020	UK pence	48.94	50.05	24.26	23.50	146.75
	US cents	63.00	63.00	31.50	31.50	189.00
2021	UK pence	22.61	22.27	23.72	24.63	92.23
	US cents	31.50	31.50	32.76	32.76	128.52
2022	UK pence	24.96	26.13	31.01	29.64	111.74
	US cents	32.76	32.76	36.04	36.04	137.60
2023	UK pence	33.30	31.85	34.39	34.42	133.97
	US cents	39.66	39.66	43.62	43.62	166.56
2024	**UK pence**	**34.15**	**34.10**	**36.30**	**37.78**	**142.33**
	US cents	**43.62**	**43.62**	**48.00**	**48.00**	**183.24**

a Dividends announced and paid by the company on ordinary and preference shares are provided in the consolidated Financial statements – Note 10.

There are no UK foreign exchange controls or other restrictions on the import or export of capital by, or on the payment of dividends to, non-resident holders of BP p.l.c. shares, or that materially affect the conduct of BP p.l.c's operations, other than restrictions applicable to certain countries and persons subject to UN, US, UK, or EU economic sanctions, to the extent these restrictions can be complied with in law.

Shareholder taxation information

This section describes the material US federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder who holds the ordinary shares or ADSs as capital assets for tax purposes. This section does not discuss tax consequences arising under the Medicare contribution tax on net investment income or the alternative minimum tax. It also does not apply inter alia to members of special classes of holders some of which may be subject to other rules, including: tax-exempt entities, life insurance companies, dealers in securities, traders in securities that elect a mark-to-market method of accounting for securities holdings, holders that, actually or constructively, hold 10% or more of the company's shares (as measured by voting power or value), holders that hold the shares or ADSs as part of a straddle or a hedging or conversion transaction, holders that purchase or sell the shares or ADSs as part of a wash sale for US federal income tax purposes, or holders whose functional currency is not the US dollar. In addition, if a partnership holds the shares or ADSs, the US federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership and may not be described fully below.

A US holder is any beneficial owner of ordinary shares or ADSs that is for US federal income tax purposes (1) a citizen or resident of the US, (2) a US domestic corporation, (3) an estate whose income is subject to US federal income taxation regardless of its source, or (4) a trust if a US court can exercise primary supervision over the trust's administration and one or more US persons are authorized to control all substantial decisions of the trust.

This section is based on the tax laws of the United States, including the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed US Treasury regulations thereunder, published rulings and court decisions, and the taxation laws of the UK, all as currently in effect, as well as the income tax convention between the US and the UK that entered into force on 31 March 2003 (the Treaty). These laws are subject to change, possibly on a retroactive basis. This section further assumes that each obligation under the terms of the deposit agreement relating to bp ADSs and any related agreement will be performed in accordance with its terms.

For purposes of the Treaty and the estate and gift tax convention between the US and the UK that entered into force on 11 November 1979 (the Estate Tax Convention) and for US federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the company's ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs and ADRs for ordinary shares generally will not be subject to US federal income tax or to UK taxation other than stamp duty or stamp duty reserve tax, as described below.

Investors should consult their own tax advisor regarding the US federal, state and local, UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Treaty in respect of their investment in the shares or ADSs.

Taxation of dividends

UK taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the company, including dividends paid to US holders. A US holder that is a company resident for tax purposes in the UK or trading in the UK through a permanent establishment generally will not be taxable in the UK on a dividend it receives from the company. A US holder who is an individual resident for tax purposes in the UK is subject to UK tax on dividends received from the company, including dividends paid but reinvested under any dividend reinvestment plan for ordinary shareholders, that are in excess of the annual dividend allowance. However, if the shareholder's dividend income is covered by their personal allowance of £12,570 (for 2024/25) after taking into account other sources of income, no UK tax will be payable on their dividend income.

For 2024/25 the dividend allowance is £500 which means there is no UK tax due on the first £500 of dividends received. Dividends above this level are subject to tax at 8.75% for basic tax payers, 33.75% for higher rate tax payers and 39.35% for additional rate tax payers.

Although the first £500 of dividend income is not subject to UK income tax, it does not reduce the total income for tax purposes. Dividends within the dividend allowance still count towards basic or higher rate bands, and may therefore affect the rate of tax paid on dividends received in excess of the £500 allowance. For instance, if an individual has an annual gross salary of £55,000 and also receives a dividend of £12,000 they will be subject to the following scenario. The individual's personal allowance and the basic rate tax band will be used up by the gross salary. The remaining part of the salary and the whole of the dividend will be subject to tax at the higher rate, although the dividend allowance will reduce the amount of dividend subject to tax. The dividend of £12,000 will be reduced by the dividend allowance of £500 leaving taxable dividend income of £11,500. The dividend will be taxed at 33.75% so that the total tax payable on the dividends is £3,881.

An individual US holder should inform HM Revenue & Customs each year for which that US holder receives dividends chargeable to UK tax. If a US holder needs to report to HMRC and already files a self-assessment tax return in the UK, the US holder should include the dividend income in that return and submit it by the deadline. If the US holder does not file a self-assessment return, the US holder should inform HM Revenue & Customs by 5 October. How the income is reported and taxed will depend on the size of the dividend income for that tax year. If the US holder received dividend income up to £10,000, the US holder can inform HM Revenue & Customs by either asking to update his or her tax code or contacting the helpline. If the US holder's dividend income is over £10,000, he or she will need to fill out a self-assessment tax return. For this, the US holder will need to register for self-assessment by 5 October. A US holder will not need to report his or her dividend income to HM Revenue & Customs if the amount is within his or her dividend allowance for that tax year.

US federal income taxation

A US holder is subject to US federal income taxation on the gross amount of any dividend paid by the company (including dividends paid but reinvested under the Global Invest Direct (GID) Dividend Reinvestment Plan for ADS holders) out of its current or accumulated earnings and profits (as determined for US federal income tax purposes). Dividends paid to a non-corporate US holder that constitute qualified dividend income will be taxable to the holder at a preferential rate, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the company with respect to the ordinary shares or ADSs will generally be qualified dividend income.

For US federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depositary, in the case of ADSs, actually or constructively receives the dividend and will not be eligible for the dividends-received deduction generally allowed to US corporations in respect of dividends received from other US corporations. US ADS holders should consult their own tax advisor regarding the US tax treatment of the dividend fee in respect of dividends. Dividends will generally be income from sources outside the US and generally will be 'passive category income' for purposes of computing a US holder's foreign tax credit limitation.

As noted above in UK taxation, a US holder will not be subject to UK withholding tax. Accordingly, the receipt of a dividend will not entitle the US holder to a foreign tax credit.

The amount of the dividend distribution on the ordinary shares that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/US dollar rate on the date the dividend is distributed, regardless of whether the payment is, in fact, converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is distributed to the date the payment is converted into US dollars will be treated as ordinary income or loss and will not be eligible for the preferential tax rate on qualified dividend income. The gain or loss generally will be income or loss from sources within the US for foreign tax credit limitation purposes.

Distributions in excess of the company's earnings and profits, as determined for US federal income tax purposes, will be treated as a return of capital to the extent of the US holder's basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described in 'Taxation of capital gains – US federal income taxation' section below.

In addition, the taxation of dividends may be subject to the rules for passive foreign investment companies (PFIC), described below under 'Taxation of capital gains – US federal income taxation'. Distributions made by a PFIC do not constitute qualified dividend income and are not eligible for the preferential tax rate applicable to such income.

Taxation of capital gains

UK taxation

A US holder may be liable for both UK and US tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (1) resident for tax purposes in the UK at the date of disposal, (2) person who (a) has left the UK; (b) was resident in the UK for four out of the seven years before the year of departure; (c) acquired the shares before leaving the UK; (d) sold the shares while not resident in the UK; and (e) returns to the UK within a period not exceeding five complete tax years after departure, (3) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK, or (4) a citizen of the US that carries on a trade or profession or vocation in the UK through a branch or agency or a corporation that carries on a trade, profession or vocation in the UK, through a permanent establishment, and that has used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment.

Under the Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence of the relevant holder as determined under both the laws of the UK and the US and as required by the terms of the Treaty.

Under the Treaty, individuals who are residents of either the UK or the US and who have been residents of the other jurisdiction (the US or the UK, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the company not only in the jurisdiction of which the holder is resident at the time of the disposition but also in the other jurisdiction.

The UK Capital Gains Tax rate is dependent on the level of an individual's taxable income. For 2024/25, the revised rates are as follows:

★ See glossary on **page 351**

Gains up until 29 October 2024, where total taxable income and gains after all allowable deductions are less than the upper limit of the basic rate income tax band of £37,700 (for 2024/25), the rate of Capital Gains Tax will be 10%. For gains (and any parts of gains) above that limit the rate will be 20%.

Gains from 30 October 2024 onwards, where total taxable income and gains after all allowable deductions are less than the upper limit of the basic rate income tax band of £37,700 (for 2024/25), the rate of Capital Gains Tax will be 18%. For gains (and any parts of gains) above that limit the rate will be 24%.

An individual may be entitled to a capital gains tax free allowance, depending on that individual's circumstances (in particular, election for the remittance basis of taxation). For individuals who are entitled to the allowance for 2024/25, this has been set at £3,000. Corporation tax on chargeable gains is levied at 25% for companies from 1 April 2023.

US federal income taxation

A US holder who sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for US federal income tax purposes equal to the difference between the US dollar value of the amount realized on the disposition and the US holder's tax basis, determined in US dollars, in the ordinary shares or ADSs. Any such capital gain or loss generally will be long-term gain or loss, subject to tax at a preferential rate for a non-corporate US holder, if the US holder's holding period for such ordinary shares or ADSs exceeds one year. The tax basis of shares acquired through reinvested dividends under the GID Dividend Reinvestment Plan for ADS holders is equal to the fair market value of the stock on the investment date. The holding period for shares acquired under the plan begins the day after the applicable investment date.

Gain or loss from the sale or other disposition of ordinary shares or ADSs will generally be income or loss from sources within the US for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

We do not believe that ordinary shares or ADSs will be treated as stock of a passive foreign investment company (PFIC) for US federal income tax purposes, but this conclusion is a factual determination that is made annually and thus is subject to change. If we are treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to ordinary shares or ADSs, any gain realized on the sale or other disposition of ordinary shares or ADSs would in general not be treated as capital gain. Instead, a US holder would be treated as if he or she had realized such gain rateably over the holding period for ordinary shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, in addition to which an interest charge in respect of the tax attributable to each such year would apply. Certain 'excess distributions' would be similarly treated if we were treated as a PFIC.

Additional tax considerations

Scrip Programme

Until the publication of the 2019 third quarter results, the company had an optional Scrip Programme, wherein holders of bp ordinary shares or ADSs could elect to receive any dividends in the form of new fully paid ordinary shares or ADSs of the company instead of cash. Please consult your tax advisor for the consequences to you.

UK inheritance tax

The Estate Tax Convention applies to UK inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is for the purposes of the Estate Tax Convention a national of the US and not a national of the UK will not be subject to UK inheritance tax on the individual's death or on transfer during the individual's lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK or a fixed base used for the performance of independent personal services. In the exceptional case where ADSs are subject to both inheritance tax and US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

UK stamp duty and stamp duty reserve tax

The statements below relate to what is understood to be the current practice of HM Revenue & Customs in the UK under existing law.

Provided that any instrument of transfer is not executed in the UK and remains at all times outside the UK and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of £5 per £1,000 (or part, unless the stamp duty is less than £5, when no stamp duty is charged), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser.

A subsequent transfer of ordinary shares to the Depositary's nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer. For ADR holders electing to receive ADSs instead of cash, after the 2012 first quarter dividend payment, HM Revenue & Customs no longer seeks to impose 1.5% stamp duty reserve tax on issues of UK shares and securities to non-EU clearance services and depositary receipt systems.

Major shareholders

The disclosure of certain major and significant shareholdings in the share capital of the company is governed by the Companies Act 2006, the UK Financial Conduct Authority's Disclosure Guidance and Transparency Rules (DTR) and the US Securities Exchange Act of 1934.

Register of members holding bp ordinary shares as at 31 December 2024

Range of holdings	Number of ordinary shareholders	Percentage of total ordinary shareholders	Percentage of total ordinary share capital excluding shares held in treasury
1-200	51,042	26.34	0.02
201-1,000	62,834	32.42	0.21
1,001-10,000	69,939	36.09	1.36
10,001-100,000	8,749	4.51	1.12
100,001-1,000,000	677	0.35	1.50
Over 1,000,000[a]	555	0.29	95.79
Totals	193,796	100	100

a Includes JPMorgan Chase Bank, N.A. holding 25.92% of the total ordinary issued share capital (excluding shares held in treasury) as the approved depositary for ADSs, a breakdown of which is shown in the table below.

Register of holders of American depositary shares (ADSs) as at 31 December 2024[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	35,241	59.39	0.18
201-1,000	15,660	26.39	0.71
1,001-10,000	8,136	13.71	1.96
10,001-100,000	299	0.50	0.47
100,001-1,000,000	4	0.01	0.07
Over 1,000,000[b]	2	0.00	96.63
Totals	59,342	100	100

a One ADS represents six 25 cent ordinary shares.
b One holder of ADSs represents 1,365,801 approx. underlying shareholders.

As at 31 December 2024 there were also 1,077 preference shareholders. Preference shareholders represented 0.52% and ordinary shareholders represented 99.48% of the total issued nominal share capital of the company (excluding shares held in treasury) as at that date.

As at 14 February 2025, the 8% preference shares and 9% preference shares in issue comprised only 0.30% and 0.23% respectively of the company's total issued nominal share capital (excluding shares held in treasury) the rest being ordinary shares.

Substantial shareholders

The following table shows holdings of 3% or more voting rights in ordinary shares of 25 cents in BP p.l.c. as per the most recent notification of each respective holder to bp under DTR 5. The percentage of voting rights detailed below was calculated as at the date of the relevant disclosures.

	As at 31 December 2024		As at 14 February 2025	
	Number of voting rights	Percentage of capital	Number of voting rights	Percentage of capital
BlackRock, Inc.	1,504,412,502	7.37	1,504,412,502	7.37
Norges Bank[a]	651,587,439	4.00	651,587,439	4.00

a In the last three financial years, BP p.l.c. received five notifications from Norges Bank relating to its voting rights. 1 - the percentage of voting rights falling below 3% on 16 March 2022; 2 - the percentage of voting rights exceeding 3% on 9 February 2023; 3 - the percentage of voting rights exceeding 4% on 12 September 2024; 4 - the percentage of voting rights falling below 4% on 20 September 2024; 5 - the percentage of voting rights exceeding 4% on 23 September 2024.

There are no current disclosable interests in holdings of 3% or more voting rights in 8% cumulative first preference shares of £1 each and 9% cumulative second preference shares of £1 each.

Largest registered shareholders

Under the US Securities Exchange Act of 1934 bp is aware of the following interests as at 14 February 2025.

Ordinary shares of $0.25 in BP p.l.c.:

Holder	Holding of ordinary shares	Percentage of ordinary share capital excluding shares held in treasury
JPMorgan Chase Bank N.A., depositary for ADSs, through its nominee Guaranty Nominees Limited	4,191,539,064	26.19
BlackRock, Inc.	1,478,584,810	9.24
Vanguard Group Holdings	792,582,730	4.95
Norges Bank	722,312,781	4.51

8% cumulative first preference shares of £1 each in BP p.l.c.:

Holder	Holding of 8% cumulative first preference shares	Percentage of class
Hargreaves Lansdown Asset Management Limited	1,370,985	18.96
Interactive Investor Share Dealing Services	968,752	13.39
Barclays, Plc.	682,038	9.43
Halifax Share Dealing Services	625,009	8.64
Canaccord Genuity Group Inc.	541,185	7.48
AJ Bell Securities, Ltd.	379,756	5.25
Ameriprise Financials, Inc.	287,500	3.97

9% cumulative second preference shares of £1 each in BP p.l.c.:

Holder	Holding of 9% cumulative second preference shares	Percentage of class
Hargreaves Lansdown Asset Management Limited	907,748	16.58
AJ Bell Securities, Ltd.	622,328	11.37
Interactive Investor Share Dealing Services	527,194	9.63
Canaccord Genuity Group Inc.	413,605	7.56
Safra Group	345,500	6.31
Halifax Share Dealing Services	292,679	5.35
Ameriprise Financials, Inc.	250,000	4.57
abrdn plc	215,000	3.93
Redmayne-Bentley LLP	179,725	3.28
Barclays, Plc.	174,656	3.19

The company's major shareholders' voting rights may differ to their total interest and can be found under the substantial shareholders heading above where voting rights are over 3%.

Annual general meeting (AGM)

The 2025 AGM is scheduled to be held on Thursday 17 April 2025 at 11:00am BST. A separate notice convening the meeting is distributed to shareholders, which includes an explanation of the items of business to be considered at the meeting.

All resolutions for which notice has been given will be decided on a poll. Deloitte LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in the *Notice of bp Annual General Meeting 2025*.

Memorandum and Articles of Association

The following summarizes certain provisions of the company's Memorandum and Articles of Association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act 2006 (the Act) and the company's Memorandum and Articles of Association. The Memorandum and Articles of Association are available online at bp.com/usefuldocs.

The company's Articles of Association may be amended by a special resolution at a general meeting of the shareholders. At the AGM held on 21 May 2018 shareholders voted to adopt new Articles of Association to reflect developments in market practice and to provide clarification and additional flexibility where necessary or appropriate.

Objects and purposes

BP p.l.c. is a public company limited by shares and registered in England and Wales with the registered number 102498. The provisions regulating the operations of the company, known as its 'objects', were historically stated in a company's memorandum. The Act abolished the need to have object provisions and so at the AGM held on 15 April 2010 shareholders approved the removal of its objects clause together with all other provisions of its Memorandum that, by virtue of the Act, are treated as forming part of the company's Articles of Association.

Directors and secretary

The business and affairs of the company shall be managed by the directors. The company's Articles of Association provide that any person may be appointed by the existing directors or by the shareholders in a general meeting either as a replacement for another director or as an additional director. Any person appointed by the directors will hold office only until the next general meeting, notice of which is first given after their appointment and will then be eligible for re-election by the shareholders. A director may be removed by the company as provided for by applicable law and shall vacate office in certain circumstances as set out in the Articles of Association. In addition, the company may, by special resolution, remove a director before the expiration of his/her period of office and, subject to the Articles of Association, may by ordinary resolution appoint another person to be a director instead. There is no requirement for a director to retire on reaching any age.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which the director has a material interest other than by virtue of such director's interest in shares in the company. However, in the absence of some other material interest not indicated below, a director is entitled to vote and to be counted in a quorum for the purpose of any vote relating to a resolution concerning the following matters:

- The giving of security or indemnity with respect to any money lent or obligation taken by the director at the request or benefit of the company or any of its subsidiary undertakings.
- The giving of security or indemnity to a third party with respect to any debt or obligation of the company or any of its subsidiary undertakings for which the director has assumed responsibility.
- Any proposal in which the director is interested, concerning the underwriting of company securities or debentures or the giving of any security to a third party for a debt or obligation of the company or any of its subsidiary undertakings.

★ See glossary on **page 351**

- Any proposal concerning any other company in which the director is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that the director and persons connected with such director are not the holder or holders of 1% or more of the voting interest in the shares of such company.
- Any proposal concerning the purchase or maintenance of any insurance policy under which the director may benefit.
- Any proposal concerning the giving to the director of any other indemnity which is on substantially the same terms as indemnities given or to be given to all of the other directors or to the funding by the company of his expenditure on defending proceedings or the doing by the company of anything to enable the director to avoid incurring such expenditure where all other directors have been given or are to be given substantially the same arrangements.
- Any proposal concerning an arrangement for the benefit of the employees and directors or former employees and former directors of the company or any of its subsidiary undertakings, including but without being limited to a retirement benefits scheme and an employees' share scheme, which does not accord to any director any privilege or advantage not generally accorded to the employees or former employees to whom the arrangement relates.

The Act requires a director of a company who is in any way interested in a contract or proposed contract with the company to declare the nature of the director's interest at a meeting of the directors of the company. The definition of 'interest' includes the interests of spouses, children, companies and trusts. The Act also requires that a director must avoid a situation where a director has, or could have, a direct or indirect interest that conflicts, or possibly may conflict, with the company's interests. The Act allows directors of public companies to authorize such conflicts where appropriate, if a company's Articles of Association so permit. The company's Articles of Association permit the authorization of such conflicts. The directors may exercise all the powers of the company to borrow money, except that the amount remaining undischarged of all moneys borrowed by the company shall not, without approval of the shareholders, exceed two times the amount paid up on the share capital plus the aggregate of the amount of the capital and revenue reserves of the company and its subsidiary undertakings incorporated in the UK. Variation of the borrowing power of the board may only be affected by amending the Articles of Association.

Remuneration of non-executive directors shall be determined in the aggregate by resolution of the shareholders. Remuneration of executive directors is determined by the remuneration committee. This committee is made up of non-executive directors only. There is no requirement of share ownership for a director's qualification.

The Articles of Association provide entitlement to the directors' pensions and death and disability benefits to the directors' relations and dependants respectively.

The circumstances in which a director's office will automatically terminate include, amongst others: when a director ceases to hold an executive office of the company and the directors resolve that they should cease to be a director; if a medical practitioner provides an opinion that a director has become incapable of acting as a director and may remain so incapable for more than a further three months and the directors resolve that they should cease to be a director; and if all of the other directors vote in favour of a resolution stating that the person should cease to be a director.

The company secretary has express powers to delegate any of the powers or discretions conferred on him or her.

Dividend rights; other rights to share in company profits; capital calls

Shareholders of the company may, by resolution, declare dividends but no such dividend may be declared in excess of the amount recommended by the directors. The directors may also pay interim dividends without obtaining shareholder approval. No dividend may be paid other than out of profits available for distribution, as determined under IFRS and the Act. Dividends on ordinary shares are payable only after payment of dividends on bp preference shares. Any dividend unclaimed after a period of 10 years from the date of declaration of such dividend shall be forfeited and reverts to bp. If the company exercises its right to forfeit shares and sells shares belonging to an untraced shareholder then any entitlement to claim dividends or other monies unclaimed in respect of those shares will be for a period of 12 months after the sale. The company may take such steps as the directors decide are appropriate in the circumstances to trace the member entitled and the sale may be made at such time and on such terms as the directors may decide.

The directors have the power to declare and pay dividends in any currency provided that a sterling equivalent is announced. It is not the company's intention to change its current policy of paying dividends in US dollars. At the company's AGM held on 15 April 2010, shareholders approved the introduction of a Scrip Dividend Programme (Scrip Programme) and to include provisions in the Articles of Association to enable the company to operate the Scrip Programme. The Scrip Programme was renewed at the company's AGM held on 25 April 2024 for a further three years. The Scrip Programme enables ordinary shareholders and bp ADS holders to elect to receive new fully paid ordinary shares (or bp ADSs in the case of bp ADS holders) instead of cash. The operation of the Scrip Programme is always subject to the directors' decision to make the scrip offer available in respect of any particular dividend. Should the directors decide not to offer the scrip in respect of any particular dividend, cash will automatically be paid instead. The directors may determine in relation to any scrip dividend plan or programme how the costs of the programme will be met, the minimum number of ordinary shares required in order to be able to participate in the programme and any arrangements to deal with legal and practical difficulties in any particular territory.

Apart from shareholders' rights to share in bp's profits by dividend (if any is declared or announced), the Articles of Association provide that the directors may set aside:

- A special reserve fund out of the balance of profits each year to make up any deficit of cumulative dividend on the bp preference shares.
- A general reserve out of the balance of profits each year, which shall be applicable for any purpose to which the profits of the company may properly be applied. This may include capitalization of such sum, pursuant to an ordinary shareholders' resolution, and distribution to shareholders as if it were distributed by way of a dividend on the ordinary shares or in paying up in full unissued ordinary shares for allotment and distribution as bonus shares.

Any such sums so deposited may be distributed in accordance with the manner of distribution of dividends as described above.

Holders of shares are not subject to calls on capital by the company, provided that the amounts required to be paid on issue have been paid off. All shares are fully paid.

Share transfers and share certificates

The directors may permit transfers to be effected other than by an instrument in writing. Share certificates will not be required to be issued by the company if they are not required by law.

The company may charge an administrative fee in the event that a shareholder wishes to replace two or more certificates representing shares with a single certificate or wishes to surrender a single certificate and replace it with two or more certificates. All certificates are sent at the member's risk.

Voting rights

The Articles of Association of the company provide that voting on resolutions at a shareholders' meeting will be decided on a poll other than resolutions of a procedural nature, which may be decided on a show of hands. If voting is on a poll, every shareholder who is present in person or by proxy has one vote for every ordinary share held and two votes for every £5 in nominal amount of bp preference shares held. If voting is on a show of hands, each shareholder who is present at the meeting in person or whose duly appointed proxy is present in person will have one vote, regardless of the number of shares held, unless a poll is requested.

Shareholders do not have cumulative voting rights.

For the purposes of determining which persons are entitled to attend or vote at a shareholders' meeting and how many votes such persons may cast, the company may specify in the notice of the meeting a time, not more than 48 hours before the time of the meeting, by which a person who holds shares in registered form must be entered on the company's register of members in order to have the right to attend or vote at the meeting or to appoint a proxy to do so.

Holders on record of ordinary shares may appoint a proxy, including a beneficial owner of those shares, to attend, speak and vote on their behalf at any shareholders' meeting, provided that a duly completed proxy form is received not less than 48 hours (or such shorter time as the directors may determine) before the time of the meeting or adjourned meeting or, where the poll is to be taken after the date of the meeting, not less than 24 hours (or such shorter time as the directors may determine) before the time of the poll.

Record holders of bp ADSs are also entitled to attend, speak and vote at any shareholders' meeting of the company by the appointment by the approved depositary, JPMorgan Chase Bank N.A., of them as proxies in respect of the ordinary shares represented by their ADSs. Each such proxy may also appoint a proxy. Alternatively, holders of bp ADSs are entitled to vote by supplying their voting instructions to the Depositary, who will vote the ordinary shares represented by their ADSs in accordance with their instructions.

Proxies may be delivered electronically.

Corporations who are members of the company may appoint one or more persons to act as their representative or representatives at any shareholders' meeting provided that the company may require a corporate representative to produce a certified copy of the resolution appointing them before they are permitted to exercise their powers.

Matters are transacted at shareholders' meetings by the proposing and passing of resolutions, of which there are two types: ordinary or special.

An ordinary resolution requires the affirmative vote of a majority of the votes cast at a meeting at which there is a quorum. A special resolution requires the affirmative vote of not less than three quarters of the votes cast at a meeting at which there is a quorum. Any AGM requires 21 clear days' notice. The notice period for any other general meeting is 14 clear days subject to the company obtaining annual shareholder approval, failing which, a 21 clear day notice period will apply.

Liquidation rights; redemption provisions

In the event of a liquidation of bp, after payment of all liabilities and applicable deductions under UK laws and subject to the payment of secured creditors, the holders of bp preference shares would be entitled to the sum of (1) the capital paid up on such shares plus, (2) accrued and unpaid dividends and (3) a premium equal to the higher of (a) 10% of the capital paid up on the bp preference shares and (b) the excess of the average market price over par value of such shares on the London Stock Exchange during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, bp may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolutions, by determination of the directors), and may issue shares that are to be or may be redeemed.

Variation of rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or on the adoption of a special resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the Articles of Association relating to proceedings at a general meeting apply, except that the quorum with respect to a meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one third or more of the shares of that class.

Shareholders' meetings and notices

Shareholders must provide bp with a postal or electronic address in the UK to be entitled to receive notice of shareholders' meetings. Holders of bp ADSs are entitled to receive notices under the terms of the deposit agreement relating to bp ADSs. The substance and timing of notices are described above under the heading Voting rights.

Under the Act, the AGM of shareholders must be held once every year, within each six-month period beginning with the day following the company's accounting reference date. All general meetings shall be held at a time and place determined by the directors. If any shareholders' meeting is adjourned for lack of quorum, notice of the time and place of the adjourned meeting may be given in any lawful manner, including electronically. Powers exist for action to be taken either before or at the meeting by authorized officers to ensure its orderly conduct and safety of those attending.

The directors have power to convene a general meeting which is a hybrid meeting, that is to provide facilities for shareholders to attend a meeting which is being held at a physical place by electronic means as well (but not to convene a purely electronic meeting).

The provisions of the Articles of Association in relation to satellite meetings permit facilities being provided by electronic means to allow those persons at each place to participate in the meeting.

Limitations on voting and shareholding

There are no limitations, either under the laws of the UK or under the company's Articles of Association, restricting the right of non-resident or foreign owners to hold or vote bp ordinary or preference shares in the company other than limitations that would generally apply to all of the shareholders and limitations applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

Disclosure of interests in shares

The Act permits a public company to give notice to any person whom the company believes to be or, at any time during the three years prior to the issue of the notice, to have been interested in its voting shares requiring them to disclose certain information with respect to those interests. Failure to supply the information required may lead to disenfranchisement of the relevant shares and a prohibition on their transfer and receipt of dividends and other payments in respect of those shares and any new shares in the company issued in respect of those shares. In this context the term 'interest' is widely defined and will generally include an interest of any kind whatsoever in voting shares, including any interest of a holder of bp ADSs.

Called-up share capital

Details of the allotted, called-up and fully-paid share capital at 31 December 2024 are set out in Financial statements – Note 31. In accordance with institutional investor guidelines, the company deems it appropriate to grant authority to the directors to allot shares and other securities and to disapply pre-emption rights by way of shareholders' resolutions at each AGM in place of authority granted by virtue of the company's Articles of Association. At the AGM on 25 April 2024, authorization was given to the directors to allot shares in the company and to grant rights to subscribe for, or to convert any security into, shares in the company up to an aggregate nominal amount as set out in the Notice of Annual General Meeting *2024*. These authorities were given for the period until the next AGM in 2025 or 25 July 2025, whichever is the earlier. These authorities are renewed annually at the AGM.

Company records and service of notice

In relation to notices not covered by the Act, the reference to notice by advertisement in a national newspaper also includes advertisements via other means such as a public announcement.

★ See glossary on **page 351**

Purchases of equity securities by the issuer and affiliated purchasers

During the 2024 financial year the company repurchased 1,238,335,234 ordinary shares with a nominal value of $0.25 each for a total consideration of $7,127,061,186 (including transaction costs), for the purpose of reducing the issued share capital of the company in order to return capital to shareholders and to offset the expected dilution from the vesting of awards under employee share schemes. The shares repurchased in 2024 represented 7.65% of the company's issued share capital, excluding shares held in treasury, on 31 December 2024. Of the shares repurchased in 2024, shares purchased under the 2023 AGM authority represented 2.51%, and shares purchased under the 2024 AGM authority represented 5.14% of bp's issued share capital, excluding shares held in treasury, on 31 December 2024. A further 176,152,257 ordinary shares were repurchased between the end of the financial year and 14 February 2025 at a cost of $927,491,733 (including transaction costs) representing 1.09% of the company's issued share capital, excluding shares held in treasury, on 31 December 2024. All ordinary shares repurchased in 2024 and in 2025 up to 14 February under the share buyback programmes were cancelled.

Authorization for the company to make market purchases (as defined in section 693(4) of the Companies Act 2006) of ordinary shares with a nominal value of $0.25 each in the company was renewed at the company's 2024 AGM covering the period until the date of the company's 2025 AGM or 25 July 2025, whichever is earlier. The maximum number of ordinary shares to be purchased under this authority will not exceed 1,701,953,274 ordinary shares. The shares purchased will be cancelled.

The following table provides details of ordinary share purchases made (1) under the share buyback programmes and (2) by the Employee Share Ownership Plans (ESOPs) and other purchases of ordinary shares and ADSs made to satisfy the requirements of certain employee share-based payment plans.

	Total number of shares purchased[a]	**Average price paid per share $**	Number of shares purchased by ESOPs or for certain employee share-based plans[b]	Number of shares purchased under buyback programmes[c]	Maximum approximate dollar value of shares yet to be purchased under the programmes $ million
2024					
January 02 - January 31	**113,923,673**	**5.87**	7,312,257	106,611,416	N/A
February 1 - February 28	**93,027,315**	**5.99**		93,027,315	N/A
March 1 - March 28	**91,984,194**	**6.18**		91,984,194	N/A
April 2 - April 30	**93,129,453**	**6.50**		93,129,453	N/A
May 1 -May 31	**90,477,384**	**6.34**		90,477,384	N/A
June 3 - June 28	**95,154,515**	**6.01**		95,154,515	N/A
July 1- July 30	**125,439,524**	**5.99**		125,439,524	N/A
August 2 - August 30	**102,310,465**	**5.68**		102,310,465	N/A
September 02 -September 30	**123,588,247**	**5.45**	990,000	122,598,247	N/A
October 01 - October 31	**154,431,981**	**5.32**		154,431,981	N/A
November 1 - November 29	**90,683,490**	**4.90**		90,683,490	N/A
December 2 - December 20	**72,487,250**	**4.96**		72,487,250	N/A
2025					
January 03 - January 31	**132,132,317**	**5.25**	1,200,000	130,932,317	N/A
February 03 - February 11	**45,219,940**	**5.30**		45,219,940	N/A

a All share purchases were of ordinary shares of $0.25 each and/or ADSs (each representing six ordinary shares) and were on/open market transactions.

b Transactions represent the purchases of ordinary shares and ADSs made to satisfy requirements of certain employee share-based payment plans.

c Share repurchases from 1 January to 2 February 2024 were made under a share buyback programme announced on 31 October 2023 for a period up to and including 2 February 2024. On 6 February 2024 the company announced a programme covering a period up to and including 3 May 2024. On 7 May 2024 the company announced a programme covering a period up to and including 26 July 2024. The company announced two programmes in one announcement on 30 July 2024. One covered a period up to and including 25 October 2024 and the other, relating to employee share schemes, was for a period up to and including 30 September 2024. On 29 October 2024 the company announced a programme covering a period up to and including 7 February 2025. On 11 February 2025 the company announced its intent to execute a $1.75 billion share buyback prior to reporting its first quarter 2025 company and group results.

Fees and charges payable by ADS holders

The Depositary collects fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of the distributable property to pay the fees.

The charges of the Depositary payable by investors are as follows:

Type of service	Depositary actions	Fee
Depositing or substituting the underlying shares	Issuance of ADSs against the deposit of shares, including deposits and issuances in respect of: • Share distributions, stock splits, rights, merger. • Exchange of securities or other transactions or event or other distribution affecting the ADSs or deposited securities.	$5.00 per 100 ADSs (or portion thereof) evidenced by the new ADSs delivered.
Selling or exercising rights	Distribution or sale of securities, the fee being an amount equal to the fee for the execution and delivery of ADSs that would have been charged as a result of the deposit of such securities.	$5.00 per 100 ADSs (or portion thereof).
Withdrawing an underlying share	Acceptance of ADSs surrendered for withdrawal of deposited securities.	$5.00 for each 100 ADSs (or portion thereof) evidenced by the ADSs surrendered.
Expenses of the Depositary	Expenses incurred on behalf of holders in connection with: • Stock transfer or other taxes and governmental charges. • Delivery by cable, telex, electronic and facsimile transmission. • Transfer or registration fees, if applicable, for the registration of transfers of underlying shares. • Expenses of the Depositary in connection with the conversion of foreign currency into US dollars (which are paid out of such foreign currency).	Expenses payable are subject to agreement between the company and the Depositary by billing holders or by deducting charges from one or more cash dividends or other cash distributions.
Dividend fees	ADS holders who receive a cash dividend are charged a fee which bp uses to offset the costs associated with administering the ADS programme.	The Deposit Agreement provides that a fee of $0.05 or less per ADS can be charged. The current fee is $0.02 per bp ADS per calendar year (equivalent to $0.005 per bp ADS per quarter per cash distribution).
Global Invest Direct (GID) Plan	New investors and existing ADS holders can buy, sell or reinvest dividends into further bp ADSs by enrolling in bp's GID Plan, sponsored and administered by the Depositary.	Cost per transaction is $2.00 for recurring, $2.00 for one-time automatic investments, and $5.00 for investment made by check. Dividend reinvestment is 5% of the dividend amount up to a maximum of $5.00. Purchase trading commission is $0.12 per share.

Fees and payments made by the Depositary to the issuer

The Depositary has agreed to reimburse certain company expenses related to the company's ADS programme and incurred by the company in connection with the ADS programme arising during the year ended 31 December 2024. The Depositary reimbursed to the company, or paid amounts on the company's behalf to third parties, or waived its fees and expenses, of $15,748,804.07 for the year ended 31 December 2024.

The table below sets out the types of expenses that the Depositary has agreed to reimburse and the fees it has agreed to waive for standard costs associated with the administration of the ADS programme relating to the year ended 31 December 2024.

Category of expense reimbursed, waived or paid directly to third parties	Amount reimbursed, waived or paid directly to third parties for the year ended 31 December 2024 $
Fees for delivery and surrender of bp ADSs	2,071,528.80
Dividend fees	13,677,275.27
Waived fees	—
Total	15,748,804.07

a Dividend fees are charged to ADS holders who receive a cash distribution, which bp uses to offset the costs associated with administering the ADS programme.

Under certain circumstances, including removal of the Depositary or termination of the ADS programme by the company, the company is required to repay the Depositary certain amounts reimbursed and/or expenses paid to or on behalf of the company during the 12-month period prior to notice of removal or termination.

Documents on display

The bp Annual Report and Form 20-F 2024 is available online at bp.com/annualreport. To obtain a hard copy of bp's complete audited financial statements, free of charge, UK based shareholders should contact bp Distribution Services by calling +44 (0) 800 037 2172 or by emailing bpdistributionservices@bp.com. If based in the US or Canada shareholders should contact Issuer Direct by calling +1 855 656 2750 or by emailing bpreports@issuerdirect.com.

The company is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, the company files its Annual Report and Form 20-F and other related documents with the SEC. The SEC maintains an internet site at sec.gov that contains reports and other information regarding issuers, including bp, that file electronically with the SEC. bp's SEC filings are also available at bp.com/sec. bp discloses in this report (see Corporate governance practices (Form 20-F Item 16G) on page 335) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

Shareholding administration

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payment options or to change the way you receive your company documents (such as the *bp Annual Report and Form 20-F* and *Notice of bp Annual General Meeting*) please contact the bp Registrar or the bp ADS Depositary.

Holders of American Depositary Receipts may request to inspect the books of the Depositary and the listing of receipt holders by contacting the bp ADS Depositary.

Ordinary and preference shareholders

The bp Registrar, MUFG Corporate Markets
Central Square,
29 Wellington Street,
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From outside the UK +44 (0)371 277 1014

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ADS holders

bp Shareowner Services
PO Box 64504, St Paul, MN 55164-0504, US

Toll-free in the US +1 877 638 5672
From outside the US +1 651 306 4383

2025 shareholder calendar[a]

28 Mar 2025	Fourth quarter interim dividend payment for 2024
17 Apr 2025	Annual general meeting
29 Apr 2025	First quarter results announced
16 May 2025	Record date (to be eligible for the first quarter interim dividend)
27 Jun 2025	First quarter interim dividend payment for 2025 and 8% and 9% preference shares record date
31 Jul 2025	8% and 9% preference shares dividend payment
05 Aug 2025	Second quarter results announced
15 Aug 2025	Record date (to be eligible for the second quarter interim dividend)
19 Sep 2025	Second quarter interim dividend payment for 2025
04 Nov 2025	Third quarter results announced
14 Nov 2025	Record date (to be eligible for the third quarter interim dividend)
19 Dec 2025	Third quarter interim dividend payment for 2025

a All future dates are provisional and may be subject to change. For the full calendar see bp.com/financialcalendar.

Glossary
Abbreviations

ADR
American depositary receipt.

ADS
American depositary share. 1 ADS = 6 ordinary shares.

Barrel (bbl)
159 litres, 42 US gallons.

bcf
Billion cubic feet.

bcfe
Billion cubic feet equivalent.

boe
Barrels of oil equivalent.

CAGR
Compound annual growth rate.

EJ/yr
Exajoules per year.

EVP
Executive vice president.

FPSO
Floating production, storage and offloading.

GAAP
Generally accepted accounting practice.

Gas
Natural gas.

gCO_2e/MJ
Grams of carbon dioxide equivalent per megajoule of energy.

GHG
Greenhouse gas.

GRI
Global Reporting Initiative.

$GtCO_2$
Gigatonnes of carbon dioxide.

GW
Gigawatt.

GWh
Gigawatt hour.

HSSE
Health, safety, security and environment.

IFRS
International Financial Reporting Standards.

kb/d
Thousand barrels per day.

KPIs
Key performance indicators.

kt
Thousand tonnes.

LNG
Liquefied natural gas.

LPG
Liquefied petroleum gas.

mb/d
Thousand barrels per day.

Mbbl
Million barrels.

mboe/d
Thousand barrels of oil equivalent per day.

mmb/d
Million barrels per day.

mmboe/d
Million barrels of oil equivalent per day.

mmBtu
Million British thermal units.

mmcf/d
Million cubic feet per day.

Mt
Million tonnes.

$MtCO_2e$
Million tonnes of CO_2 equivalent.

Mtpa
Million tonnes per annum.

MW
Megawatt.

MWe
Megawatt electrical.

MWp
Megawatt peak.

NGLs
Natural gas liquids.

PSA
Production-sharing agreement.

PTA
Purified terephthalic acid.

RC
Replacement cost.

SEC
The United States Securities and Exchange Commission.

TWh
Terawatt hour.

SVP
Senior vice president.

scfm
Standard cubic feet per minute

★ See glossary on **page 351**

Definitions

Unless the context indicates otherwise, the definitions for the following glossary terms are given below.

Non-IFRS measures are sometimes referred to as alternative performance measures.

CA100+ resolution glossary

CA100+ resolution

The CA100+ resolution means the special resolution requisitioned by Climate Action 100+ and passed at bp's 2019 Annual General Meeting, the text of which is set out below.

Special resolution: Climate Action 100+ shareholder resolution on climate change disclosures
That in order to promote the long-term success of the company, given the recognized risks and opportunities associated with climate change, we as shareholders direct the company to include in its strategic report and/or other corporate reports, as appropriate, for the year ending 2019 onwards, a description of its strategy which the board considers, in good faith, to be consistent with the goals of Articles 2.1(a)(1) and 4.1(2) of the Paris Agreement (3) (the Paris goals), as well as:

(1) Capital expenditure: how the company evaluates the consistency of each new material capex investment, including in the exploration, acquisition or development of oil and gas resources and reserves and other energy sources and technologies, with (a) the Paris goals and separately (b) a range of other outcomes relevant to its strategy.
(2) Metrics and targets: the company's principal metrics and relevant targets or goals over the short, medium and/or long term, consistent with the Paris goals, together with disclosure of:

  a. The anticipated levels of investment in (i) oil and gas resources and reserves; and (ii) other energy sources and technologies.
  b. The company's targets to promote reductions in its operational greenhouse gas emissions, to be reviewed in line with changing protocols and other relevant factors.
  c. The estimated carbon intensity of the company's energy products and progress on carbon intensity over time.
  d. Any linkage between the above targets and executive remuneration.

(3) Progress reporting: an annual review of progress against (1) and (2) above.

Such disclosure and reporting to include the criteria and summaries of the methodology and core assumptions used, and to omit commercially confidential or competitively sensitive information and be prepared at reasonable cost; and provided that nothing in this resolution shall limit the company's powers to set and vary its strategy, or associated targets or metrics, or to take any action which it believes in good faith, would best promote the long-term success of the company.

The Paris goals
(1) Article 2.1(a) of the Paris Agreement states the goal of 'Holding the increase in the global average temperature to well-below-2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change'.
(2) Article 4.1 of the Paris Agreement: In order to achieve the long-term temperature goal set out in Article 2, parties aim to reach global peaking of greenhouse gas emissions as soon as possible, recognizing that peaking will take longer for developing country parties, and to undertake rapid reductions thereafter in accordance with best available science, so as to achieve a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases in the second half of this century, on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty.
(3) U.N. Framework Convention on Climate Change Conference of Parties, Twenty-First Session, Adoption of the Paris Agreement, U.N. Doc. FCCC/CP/2015/L.9/Rev.1 (Dec. 12, 2015).

New material capex investment

For the purposes of the 2024 evaluation discussed on pages 20-23, 'new material capex investment' means a decision taken by the resource commitment meeting (RCM) in 2024 to incur inorganic or organic investments greater than $250 million that relate to a new project or asset, extending an existing project or asset, or acquiring or increasing a share in a project, asset or entity.

Material capex evaluation: Paris-consistency quantitative tests.
For the purposes of evaluating material capex investments for consistency with the Paris goals, two quantitative tests were applied, see page 22.

Operational carbon intensity (CI)

The annual average operational GHG emissions ($TeCO_2e$/unit), divided by the relevant unit of output:

- Per thousand barrels of oil equivalent in upstream.
- Per utilized equivalent distillation capacity in refining.
- per thousand tonnes of petrochemicals production.

Net zero aims and ambition glossary

Average carbon intensity of sold energy products

The rate of GHG emissions per unit of energy delivered (in grams CO_2e/MJ) estimated in respect of sold energy products★. GHG emissions are estimated on a lifecycle basis covering use, production, and distribution of sold energy products.

Emissions from the carbon in our upstream oil and gas production

Estimated CO_2 emissions from the combustion of upstream production of crude oil, natural gas and natural gas liquids (NGLs) based on bp's net share of production, excluding bp's share of Rosneft production and assuming that all produced volumes undergo full stoichiometric combustion to CO_2.

Energy products

For the purposes of our 2024 disclosures relating to net zero sales★ we consider an energy product to be one that is emissive or provides energy in its end use case. For further information on products included in bp's 2024 net zero sales aim reporting see the Basis of Reporting *bp.com/basisofreporting*.

Methane intensity

Methane intensity refers to the amount of methane emissions from bp's operated upstream oil and gas assets as a percentage of the total gas that goes to market from those operations. Our methodology is aligned with the Oil and Gas Climate Initiative (OGCI) methodology.

Net zero

References to global net zero in the phrase, 'to help the world get to net zero', means achieving '...a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases...on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty', as set out in Article 4(1) of the Paris Agreement.

References to net zero for bp in the context of our ambition and net zero operations and net zero sales aims mean achieving a balance between (a) the relevant Scope 1 and 2 emissions (for net zero operations) and product lifecycle emissions (for net zero sales) and (b) the aggregate of applicable deductions from qualifying activities such as sinks under our methodology at the applicable time.

Net zero★ operations

bp's aim to reach net zero operational greenhouse gas (CO_2 and methane) emissions by 2050 or sooner, on a gross operational control basis, in accordance with bp's net zero operations aim, which relates to our reported Scope 1 and 2 emissions. Any interim target or aim in respect of bp's net zero operations aim is defined in terms of absolute reductions relative to the baseline year of 2019.

Net zero★ production

In relation to bp's now retired (as of February 2025) 'aim 2', to reach net zero CO_2 emissions from the carbon in our upstream oil and gas production, in respect of the estimated CO_2 emissions from the combustion of upstream production of crude oil, natural gas and natural gas liquids (based on bp's net share of production, excluding bp's share of Rosneft production and assuming that all produced volumes undergo full stoichiometric combustion to CO_2). This aim previously related to Scope 3 category 11 emissions within the selected boundary of bp's net share of upstream production of oil and gas.

Net zero★ sales

bp's aim to reach net zero for the carbon intensity of sold energy products★. Any interim target or aim in respect of bp's net zero sales aim is defined in terms of reductions in the carbon intensity of the energy products we sell (in grams CO_2e/MJ) relative to the baseline year of 2019.

Sold energy products

For the purposes of bp's net zero sales aim, sold energy products★ represent sales by a bp group subsidiary, joint operation or bp equity accounted entity (EAE). For further information see the Basis of Reporting *bp.com/basisofreporting*.

Adjusted EBIDA

Adjusted EBIDA is a non-IFRS measure and is defined as profit or loss for the period, adjusting for finance costs and net finance (income) or expense relating to pensions and other post-employment benefits and taxation, inventory holding gains or losses before tax, net adjusting items★ before interest and tax, and taxation on an underlying RC basis, and adding back depreciation, depletion and amortization (pre-tax) and exploration expenditure written-off (net of adjusting items, pre-tax). bp believes that adjusted EBIDA is a useful measure for investors because it is a measure closely tracked by management to evaluate bp's operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is profit or loss for the period. A reconciliation of profit or loss for the period to adjusted EBIDA is provided on page 361.

Adjusted EBIDA per share compound annual growth rate (CAGR)

Non-IFRS measure. Adjusted EBIDA per share is calculated based on the shares in issue at period end.

Adjusted EBITDA

Adjusted EBITDA is a non-IFRS measure presented for bp's operating segments and the group. Adjusted EBITDA for bp's operating segments is defined as replacement cost (RC) profit before interest and tax, excluding net adjusting items before interest and tax, and adding back depreciation, depletion and amortization and exploration write-offs (net of adjusting items). Adjusted EBITDA by business is a further analysis of adjusted EBITDA for the customers & products businesses. bp believes it is helpful to disclose adjusted EBITDA by operating segment and by business because it reflects how the segments measure underlying business delivery. The nearest equivalent measure on an IFRS basis for the segment is RC profit or loss before interest and tax, which is bp's measure of profit or loss that is required to be disclosed for each operating segment under IFRS. A reconciliation to IFRS information is provided on pages 327 and 362.

Adjusted EBITDA for the group is defined as profit or loss for the period, adjusting for finance costs and net finance (income) or expense relating to pensions and other post-employment benefits and taxation, inventory holding gains or losses before tax, net adjusting items before interest and tax, and adding back depreciation, depletion and amortization (pre-tax) and exploration expenditure written-off (net of adjusting items, pre-tax). The nearest equivalent measure on an IFRS basis for the group is profit or loss for the period. A reconciliation to IFRS information is provided on page 362.

Adjusted free cash flow

Non-IFRS measure. It is defined as adjusted operating cash flow★ (see below) less capital expenditure★.

bp believes the measure provides useful information to investors. Adjusted free cash flow enables investors to measure our progress on delivering growth and improving our performance. The nearest IFRS measures are net cash provided by (used in) operating activities and total cash capital expenditure.

We are unable to present reconciliations of forward-looking information for adjusted free cash flow to net cash provided by operating activities, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include inventory holding gains or losses, fair value accounting effects and other adjusting items, that are difficult to predict in advance in order to include in an IFRS estimate.

Adjusted free cash flow compound annual growth rate (CAGR)

Non-IFRS measure. It is annualized growth rate of adjusted free cash flow★ (defined above) at $70/bbl Brent, $4/mmBtu Henry Hub, and $17/bbl refining marker margin, all 2024 real.

bp believes the measure provides useful information to investors. Adjusted free cash flow CAGR enables investors to measure our progress on delivering growth and improving our performance. The nearest IFRS measure is the annualized growth rate of net cash provided by (used in) operating activities.

We are unable to present reconciliations of forward-looking information for adjusted free cash flow to net cash provided by operating activities, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include inventory holding gains or losses, fair value accounting effects and other adjusting items, that are difficult to predict in advance in order to include in an IFRS estimate.

Adjusted operating cash flow

Non-IFRS measure. It is defined as net cash provided by (used in) operating activities as presented in the group cash flow statement, excluding movements in inventories and other current and non-current assets and liabilities as presented in the group cash flow statement, adjusted for inventory holding gains/losses, fair value accounting effects (FVAEs) relating to subsidiaries and other adjusting items relating to the non-cash movement of US emissions obligations carried as a provision that will be settled by allowances held as inventory. When used in the context of a segment or subset of businesses rather than the group, the terms refer to the segment or business' estimated share thereof.

bp believes the measure provides useful information to investors. Adjusted operating cash flow enables investors to measure our progress on delivering growth and improving our performance. The nearest IFRS measure is net cash provided by (used in) operating activities.

We are unable to present reconciliations of forward-looking information for adjusted operating cash flow to net cash provided by operating activities, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include inventory holding gains or losses, FVAEs and other adjusting items, that are difficult to predict in advance in order to include in an IFRS estimate.

Adjusting items

Adjusting items are items that bp discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers to be important to period-on-period analysis of the group's results and are disclosed in order to enable investors to better understand and evaluate the group's reported financial performance. Adjusting items include gains and losses on the sale of businesses and fixed assets, impairments, environmental and related provisions and charges, restructuring, integration and rationalization costs, fair value accounting effects, costs relating to the Gulf of America oil spill and other items. Adjusting items within equity-accounted earnings are reported net of incremental income tax reported by the equity-accounted entity. Adjusting items are used as a reconciling adjustment to derive underlying RC profit or loss and related underlying measures which are non-IFRS measures. An analysis of adjusting items by segment and type is shown on page 313.

Associate

An entity over which the group has significant influence and that is neither a subsidiary nor a joint arrangement of the group. Significant influence is the power to participate in the financial and operating policy decisions of the investee but is not control or joint control over those policies.

Biofuels production

Biofuels production is average thousands of barrels of biofuel production per day during the period covered net to bp. This includes equivalent ethanol production, bp bioenergy biopower for grid export, refining co-processing and standalone hydrogenated vegetable oil (HVO).

Biogas supply volumes
Biogas supply volumes is the average thousands of barrels of oil equivalent per day of production and offtakes during the period covered net to bp.

Bio-refinery
A facility that is dedicated to processing biological materials (including waste oil and crop waste) to produce biofuels such as biodiesel and sustainable aviation fuel, which may be blended to customer specifications with other components such as hydrocarbons at co-located or adjacent terminals and tanks.

Blue hydrogen
Hydrogen made from natural gas in combination with carbon captured and stored (CCS).

Capital employed
Non-IFRS measure. It is defined as total equity plus finance debt.

Capital expenditure
Total cash capital expenditure as stated in the group cash flow statement. Capital expenditure for the operating segments, gas & low carbon energy businesses and customers & products businesses is presented on the same basis.

Cash balance point
Cash balance point is defined as the implied Brent oil price 2021 real to balance bp's sources and uses of cash assuming an average bp refining marker margin around \$11/bbl and Henry Hub at \$3/mmBtu in 2021 real terms.

Commodity trading contracts
bp participates in regional and global commodity trading markets in order to manage, transact and hedge the crude oil, refined products and natural gas that the group either produces or consumes in its manufacturing operations. The range of contracts the group enters into in its commodity trading operations is described below. Using these contracts, in combination with rights to access storage and transportation capacity, allows the group to access advantageous pricing differences between locations, time periods and grades.

Exchange-traded commodity derivatives
Contracts that are typically in the form of futures and options traded on a recognized exchange, such as Nymex and ICE. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate; the main product grades, such as gasoline and gasoil; and for natural gas and power. Gains and losses, otherwise referred to as variation margin, are generally settled on a daily basis with the relevant exchange. These contracts are used for the trading and risk management of crude oil, refined products, and natural gas and power. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

Over-the-counter (OTC) contracts
Contracts that are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties or through brokers, others may be cleared by a central clearing counterparty. These contracts can be used both for trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in sales and other operating revenues for accounting purposes. Many grades of crude oil bought and sold use standard contracts including US domestic light sweet crude oil, commonly referred to as West Texas Intermediate, and a standard North Sea crude blend – Brent, Forties, Oseberg and Ekofisk (BFOE). Forward contracts are used in connection with the purchase of crude oil supplies for refineries and for marketing and sales of the group's oil production and refined products. The contracts typically contain standard delivery and settlement terms. These transactions call for physical delivery of oil with consequent operational and price risk. However, various means exist and are used from time to time, to settle obligations under the contracts in cash rather than through physical delivery. Physically settled BFOE contracts delivered by cargo additionally specify a standard volume and tolerance.

Gas and power OTC markets are highly developed in North America and the UK, where commodities can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price, with delivery and settlement at a future date. Typically, the contracts specify delivery terms for the underlying commodity. Some of these transactions are not settled physically as they can be net settled by transacting offsetting sale or purchase contracts for the same location and delivery period. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically, volume, price and term (e.g. daily, monthly and balance of month) are the main variable contract terms.

Swaps are typically contractual obligations to exchange cash flows between two parties. A typical swap transaction usually references a floating price and a fixed price with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell crude, oil products, natural gas or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry. Typically, netting agreements are used to limit credit exposure and support liquidity.

Spot and term contracts
Spot contracts are contracts to purchase or sell a commodity at the market price prevailing on or around the delivery date when title to the inventory is taken. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. As such, these transactions result in physical delivery with operational and price risk. Spot and term contracts typically relate to purchases of crude for a refinery, products for marketing, or third-party natural gas, or sales of the group's oil production, oil products or gas production to third parties. For accounting purposes, spot and term sales are included in sales and other operating revenues when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.

Consolidation adjustment – UPII
Unrealized profit in inventory arising on inter-segment transactions.

Convenience gross margin
Non-IFRS measure. Convenience gross margin is calculated as RC profit before interest and tax for the customers & products segment, excluding RC profit before interest and tax for the refining & trading business (a non-IFRS measure), and adjusting items★ (as defined above) for the convenience & mobility business to derive underlying RC profit before interest and tax for the convenience & mobility business; subtracting underlying RC profit before interest and tax for the *Castrol* business; adding back depreciation, depletion and amortization, production and manufacturing, distribution and administration expenses for convenience & mobility (excluding *Castrol*); subtracting earnings from equity-accounted entities in the convenience & mobility business (excluding *Castrol*) and gross margin for the retail fuels, EV charging, aviation, B2B and midstream businesses. bp believes it is helpful because this measure may help investors to understand and evaluate, in the same way as management, our progress against our strategic objectives of convenience growth. The nearest IFRS measure is RC profit before interest and tax for the customers & products segment.

Convenience gross margin growth
Non-IFRS measure. See convenience gross margin definition above. Convenience gross margin growth at constant foreign exchange is a non-IFRS measure. This metric requires a calculation of the comparative convenience gross margin (\$ million) at current period foreign exchange rates (constant foreign exchange) and compares the current period value with the restated comparative period value, which results in the growth % at constant foreign exchange rates. bp believes the convenience gross margin growth at constant foreign exchange are useful measures because these measures may help investors to understand and evaluate, in the same way as management, our progress against our strategic objectives of redefining convenience. The nearest IFRS measure to convenience gross margin is RC profit before interest and tax for the customer & products segment.

Convenience & EV gross margin growth (%)
Non-IFRS measure. See convenience gross margin and EV gross margin definitions. Convenience and EV gross margin growth at constant foreign exchange is a non-IFRS measure. This metric, as applicable to the directors' remuneration performance measure, requires a calculation of the

comparative convenience and EV gross margin ($ million) at current period foreign exchange rates (constant foreign exchange) and compares the current period value with the restated comparative period value, which results in the growth % at constant foreign exchange rates. The nearest IFRS measure to convenience gross margin and EV gross margin is RC profit before interest and tax for the customer & products segment.

Developed renewables to final investment decision (FID)

Total generating capacity for assets developed to FID by all entities where bp has an equity share (proportionate to equity share). If asset is subsequently sold bp will continue to record capacity as developed to FID. If bp equity share increases developed capacity to FID will increase proportionately to share increase for any assets where bp held equity at the point of FID.

Divestment proceeds

Disposal proceeds as per the group cash flow statement.

Dividend yield

Sum of the four quarterly dividends announced in respect of the year as a percentage of the year-end share price.

Dutch Title Transfer Facility

The TTF (Title Transfer Facility) is the virtual trading point for natural gas in the Netherlands. It is commonly used as a benchmark hub for gas prices in Europe.

Effective tax rate (ETR) on replacement cost (RC) profit or loss

Non-IFRS measure. The ETR on RC profit or loss is calculated by dividing taxation on a RC basis by RC profit or loss before tax. Taxation on a RC basis for the group is calculated as taxation as stated on the group income statement adjusted for taxation on inventory holding gains and losses. Information on RC profit or loss is provided below. bp believes it is helpful to disclose the ETR on RC profit or loss because this measure excludes the impact of price changes on the replacement of inventories and allows for more meaningful comparisons between reporting periods. Taxation on a RC basis and ETR on RC profit or loss are non-IFRS measures. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period. A reconciliation to IFRS information is provided on page 360.

Electric vehicle charge points / EV charge points

Defined as the number of connectors on a charging device, operated by either bp or a bp joint venture, as adjusted to be reflective of bp's accounting share of joint arrangements.

EV gross margin

Non-IFRS measure. EV gross margin, as applicable to the directors' remuneration performance measure, is calculated as RC profit before interest and tax for the customers & products segment, excluding RC profit before interest and tax for the refining & trading business (a non-IFRS measure), and adjusting items★ (as defined above) for the convenience & mobility business to derive underlying RC profit before interest and tax for the convenience & mobility business; subtracting underlying RC profit before interest and tax for the *Castrol* business; adding back depreciation, depletion and amortization, production and manufacturing, distribution and administration expenses for convenience & mobility (excluding *Castrol*); subtracting earnings from equity-accounted entities in the convenience & mobility business (excluding *Castrol*) and gross margin for the convenience and retail fuels, aviation, B2B and midstream businesses. The nearest IFRS measure to EV gross margin is RC profit before interest and tax for the customer & products segment.

Fair value accounting effects

Non-IFRS adjustments to our IFRS profit (loss).They reflect the difference between the way bp manages the economic exposure and internally measures performance of certain activities and the way those activities are measured under IFRS. Fair value accounting effects are included within adjusting items. They relate to certain of the group's commodity, interest rate and currency risk exposures as detailed below. Other than as noted below, the fair value accounting effects described are reported in both the gas & low carbon energy and customer & products segments.

bp uses derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products. Under IFRS, these inventories are recorded at historical cost. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in the income statement. This is because hedge accounting is either not permitted or not followed, principally due to the impracticality of effectiveness-testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories, other than net realizable value provisions, are not recognized until the commodity is sold in a subsequent accounting period. Gains and losses on the related derivative commodity contracts are recognized in the income statement, from the time the derivative commodity contract is entered into, on a fair value basis using forward prices consistent with the contract maturity.

bp enters into physical commodity contracts to meet certain business requirements, such as the purchase of crude for a refinery or the sale of bp's gas production. Under IFRS these physical contracts are treated as derivatives and are required to be fair valued when they are managed as part of a larger portfolio of similar transactions. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

IFRS require that inventory held for trading is recorded at its fair value using period-end spot prices, whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices, resulting in measurement differences.

bp enters into contracts for pipelines and other transportation, storage capacity, oil and gas processing, liquefied natural gas (LNG) and certain gas and power contracts that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments that are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that bp manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. bp calculates this difference for consolidated entities by comparing the IFRS result with management's internal measure of performance. We believe that disclosing management's estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole.

These include:

- Under management's internal measure of performance the inventory, transportation and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period.
- Fair value accounting effects also include changes in the fair value of the near-term portions of LNG contracts that fall within bp's risk management framework. LNG contracts are not considered derivatives, because there is insufficient market liquidity, and they are therefore accrual accounted under IFRS. However, oil and natural gas derivative financial instruments used to risk manage the near-term portions of the LNG contracts are fair valued under IFRS. The fair value accounting effect, which is reported in the gas and low carbon energy segment, represents the change in value of LNG contracts that are being risk managed and which is reflected in the underlying result, but not in reported earnings. Management believes that this gives a better representation of performance in each period.

Furthermore, the fair values of derivative instruments used to risk manage certain other oil, gas, power and other contracts, are deferred to match with the underlying exposure. The commodity contracts for business requirements are accounted for on an accruals basis.

In addition, fair value accounting effects include changes in the fair value of derivatives entered into by the group to manage currency exposure and interest rate risks relating to hybrid bonds to their respective first call periods. The hybrid bonds which are classified as equity instruments and were recorded in the balance sheet at their issuance date at their USD equivalent issued value. Under IFRS these equity instruments are not remeasured from period to period, and do not qualify for application of hedge accounting. The derivative instruments relating to the hybrid bonds, however, are required to be recorded at fair value with mark to market gains and losses recognized in the income statement. Therefore, measurement

★ See glossary on **page 351**

differences in relation to the recognition of gains and losses occur. The fair value accounting effect, which is reported in the other businesses & corporate segment, eliminates the fair value gains and losses of these derivative financial instruments that are recognized in the income statement. We believe that this gives a better representation of performance, by more appropriately reflecting the economic effect of these risk management activities, in each period.

Fast / Fast charging

Fast charging comprises rapid charging★ and ultra-fast charging★.

Finance debt ratio

Finance debt ratio is defined as the ratio of finance debt to the total of finance debt plus total equity.

Gearing and net debt

Non-IFRS measures. Net debt is calculated as finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign currency exchange and interest rate risks relating to finance debt, for which hedge accounting is applied, less cash and cash equivalents. Net debt does 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. Gearing is defined as the ratio of net debt to the total of net debt plus total equity. bp believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of finance debt, related hedges and cash and cash equivalents in total. Gearing enables investors to see how significant net debt is relative to total equity. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. See Financial statements – Note 27 for information on finance debt, which is the nearest equivalent measure to net debt on an IFRS basis. The nearest equivalent IFRS measure to gearing on an IFRS basis is finance debt ratio.

We are unable to present reconciliations of forward-looking information for net debt or gearing to finance debt and total equity, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include fair value asset (liability) of hedges related to finance debt and cash and cash equivalents, that are difficult to predict in advance in order to include in an IFRS estimate.

Gearing including leases and net debt including leases

Non-IFRS measures. Net debt including leases is calculated as net debt plus lease liabilities, less the net amount of partner receivables and payables relating to leases entered into on behalf of joint operations. Gearing including leases is defined as the ratio of net debt including leases to the total of net debt including leases plus total equity. bp believes these measures provide useful information to investors as they enable investors to understand the impact of the group's lease portfolio on net debt and gearing. See Financial statements – Note 27 for information on finance debt, which is the nearest equivalent measure to net debt including leases on an IFRS basis. The nearest equivalent IFRS measure to gearing including leases on an IFRS basis is finance debt ratio. A reconciliation to IFRS information is provided on page 315.

Green hydrogen

Hydrogen produced by electrolysis of water using renewable power.

Grey hydrogen

Produced via natural gas or coal without CCUS.

Hydrocarbons

Liquids and natural gas. Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Hydrogen pipeline

Hydrogen projects which have not been developed to final investment decision (FID) but which have advanced to the concept development stage.

Inorganic capital expenditure

A subset of capital expenditure on a cash basis and a non-IFRS measure. Inorganic capital expenditure comprises consideration in business combinations and certain other significant investments made by the group. It is reported on a cash basis. bp believes that this measure provides useful information as it allows investors to understand how bp's management invests funds in projects which expand the group's activities through acquisition. The nearest equivalent measure on an IFRS basis is capital expenditure on a cash basis. Further information and a reconciliation to IFRS information is provided on page 312.

Installed renewables capacity

Installed renewables capacity is bp's share of capacity for operating assets owned by entities where bp has an equity share.

Inventory holding gains and losses

Inventory holding gains and losses are non-IFRS adjustments to our IFRS profit (loss) and 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 of inventories other than for trading inventories, 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 as inventory holding gains and losses 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.
- An adjustment relating to certain trading inventories that are not price risk managed which relate to a minimum inventory volume that is required to be held to maintain underlying business activities. This adjustment represents the movement in fair value of the inventories due to prices, on a grade-by-grade basis, during the period. This is calculated from each operation's inventory management system on a monthly basis using the discrete monthly movement in market prices for these inventories.

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 that are price risk-managed. See Replacement cost (RC) profit or loss definition below.

Joint arrangement

An arrangement in which two or more parties have joint control.

Joint control

Contractually agreed sharing of control over an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Joint operation

A joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement.

Joint venture

A joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement.

Liquids

Comprises crude oil, condensate and natural gas liquids. For the oil production & operations segment, it also includes bitumen.

LNG portfolio

LNG portfolio refers to bp group's LNG equity production plus additional long-term merchant LNG volumes.

LNG train

An LNG train is a processing facility used to liquefy and purify natural gas in the formation of LNG.

Low carbon activity

For the purposes of FY24 and FY23 reporting an activity relating to low carbon including: renewable electricity; bioenergy; electric vehicles and other future mobility solutions; trading and marketing low carbon products; blue or green hydrogen★ and carbon capture, use and storage (CCUS).

Note that, while there is some overlap of activities, these terms do not mean the same as low carbon energy or our low carbon energy sub-segment, reported within the gas & low carbon energy segment.

Low carbon activity investment

Capital investment in relation to low carbon activity★.

Major projects

Have a bp net investment of at least $250 million, or are considered to be of strategic importance to bp or of a high degree of complexity.

Modified free cash flow

A non-IFRS measure. It is defined as Operating cash flow less: (1) net cash used in investing activities as presented in the group cash flow statement; and (2) lease liability payments included in financing activities and adjusting for receipts relating to transactions involving non-controlling interests reported within financing activities in the group cash flow statement and movements in lease creditor.

Operating cash flow

Net cash provided by (used in) operating activities as stated in the group cash flow statement. When used in the context of a segment rather than the group, the terms refer to the segment's share thereof.

Operating expenditure

Non IFRS measure and a subset of production and manufacturing expenses plus distribution and administration expenses. It represents the majority of the remaining expenses in these line items but excludes certain costs that are variable, primarily with volumes (such as freight costs). Other variable costs are included in purchases in the income statement. Management believes that operating expenditure is a performance measure that provides investors with useful information regarding the company's financial performance because it considers these expenses to be the principal operating and overhead expenses that are most directly under their control although they also include certain adjusting items★, foreign exchange and commodity price effects. The nearest IFRS measures are production and manufacturing expenses and distributions and administration expenses. A reconciliation of production and manufacturing expense plus distribution and administration expenses to operating expenditure is provided on page 363.

Operating management system (OMS)

bp's OMS helps us manage risks in our operating activities by setting out bp's principles for good operating practice. It brings together bp requirements on health, safety, security, the environment, social responsibility and operational reliability, as well as related issues, such as maintenance, contractor relations and organizational learning, into a common management system.

Organic capital expenditure

Non-IFRS measure. Organic capital expenditure comprises capital expenditure on a cash basis less inorganic capital expenditure. bp believes that this measure provides useful information as it allows investors to understand how bp's management invests funds in developing and maintaining the group's assets. The nearest equivalent measure on an IFRS basis is capital expenditure on a cash basis. An analysis of organic capital expenditure by segment and region, and a reconciliation to IFRS information is provided on page 312.

We are unable to present reconciliations of forward-looking information for organic capital expenditure to total cash capital expenditure, because without unreasonable efforts, we are unable to forecast accurately the adjusting item, inorganic capital expenditure, that is difficult to predict in advance in order to derive the nearest IFRS estimate.

Production-sharing agreement / contract (PSA / PSC)

An arrangement through which an oil and gas company bears the risks and costs of exploration, development and production. In return, if exploration is successful, the oil company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of the production remaining after such cost recovery.

Rapid / Rapid charging

Rapid charging includes electric vehicle charging of greater or equal to 50kW and less than 150kW.

Realizations

Realizations are the result of dividing revenue generated from hydrocarbon sales, excluding revenue generated from purchases made for resale and royalty volumes, by revenue generating hydrocarbon production volumes. Revenue generating hydrocarbon production reflects the bp share of production as adjusted for any production which does not generate revenue. Adjustments may include losses due to shrinkage, amounts consumed during processing, and contractual or regulatory host committed volumes such as royalties. For the gas & low carbon energy and oil production & operations segments, realizations include transfers between businesses.

Refining availability

Represents Solomon Associates' operational availability for bp-operated refineries, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all mechanical, process and regulatory downtime.

Refining marker margin (RMM)

The average of regional indicator margins weighted for bp's crude refining capacity in each region. Each regional marker margin is based on product yields and a marker crude oil deemed appropriate for the region. The regional indicator margins may not be representative of the margins achieved by bp in any period because of bp's particular refinery configurations and crude and product slate.

Replacement cost (RC) profit or loss / RC profit or loss attributable to bp shareholders

Reflects the replacement cost of inventories sold in the period and is calculated as profit or loss attributable to bp shareholders, adjusting for inventory holding gains and losses (net of tax). RC profit or loss for the group is not a recognized IFRS measure. bp believes this measure is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due to changes in prices as well as changes in underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, bp's management believes it is helpful to disclose this measure. The nearest equivalent measure on an IFRS basis is profit or loss attributable to bp shareholders. See Financial statements – Note 5. A reconciliation to IFRS information is provided on page 360.

Reported recordable injury frequency

Reported recordable injury frequency measures the number of reported work-related employee and contractor incidents that result in a fatality or injury per 200,000 hours worked. This represents reported incidents occurring within bp's operational HSSE reporting boundary. That boundary includes bp's own operated facilities and certain other locations or situations.

Renewable natural gas (RNG)

RNG is a pipeline-quality, lower carbon fuel that is interchangeable with traditional natural gas. It is a form of biogas and a product of decomposing organic material at sites including landfills, farms and wastewater treatment facilities.

★ See glossary on **page 351**

Renewables pipeline

Renewable projects satisfying the criteria below until the point they can be considered developed to FID:

Site-based projects that have obtained land exclusivity rights, or for power purchase agreement based projects an offer has been made to the counterparty, or for auction projects pre-qualification criteria have been met, or for acquisition projects post a binding offer has been accepted.

Reserves replacement ratio

The extent to which the year's production has been replaced by proved reserves added to our reserve base. The ratio is expressed in oil-equivalent terms and includes changes resulting from discoveries, improved recovery and extensions and revisions to previous estimates, but excludes changes resulting from acquisitions and disposals.

Retail sites

Retail sites include sites operated by dealers, jobbers, franchisees or brand licensees or joint venture (JV) partners, under the bp brand. These may move to and from the bp brand as their fuel supply agreement or brand licence agreement expires and are renegotiated in the normal course of business. Retail sites are primarily branded *BP*, ARCO, *Amoco*, *Aral*, *Thorntons*, and TravelCenters of America and also includes sites in India through our Jio-bp JV.

Return on average capital employed (ROACE)

Non-IFRS measure. ROACE is defined as underlying replacement cost profit, which is defined as profit or loss attributable to bp shareholders adjusted for inventory holding gains and losses, adjusting items and related taxation on inventory holding gains and losses and adjusting items total taxation, after adding back non-controlling interest and interest expense net of tax, divided by the average of the beginning and ending balances of total equity plus finance debt, excluding cash and cash equivalents and goodwill as presented on the group balance sheet over the periods presented. Interest expense before tax is finance costs as presented on the group income statement, excluding lease interest, the unwinding of the discount on provisions and other payables and other adjusting items reported in finance costs. bp believes it is helpful to disclose the ROACE because this measure gives an indication of the company's capital efficiency. The nearest IFRS measures of the numerator and denominator are profit or loss for the period attributable to bp shareholders and total equity respectively. The reconciliation of the numerator and denominator is provided on page 361.

We are unable to present forward-looking information of the nearest IFRS measures of the numerator and denominator for ROACE, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to calculate a meaningful comparable IFRS forward-looking financial measure. These items include inventory holding gains or losses and interest net of tax, that are difficult to predict in advance in order to include in an IFRS estimate.

Strategic convenience sites

Strategic convenience sites are retail sites, within the bp portfolio, which sell bp-supplied vehicle energy (e.g. *BP*, *Aral*, Arco, *Amoco*, *Thorntons*, *bp pulse*, TravelCenters of America and *PETRO*) and either carry one of the strategic convenience brands (e.g. M&S, Rewe to Go) or a differentiated bp-controlled convenience offer. To be considered a strategic convenience site, the convenience offer should have a demonstrable level of differentiation in the market in which it operates. Strategic convenience site count includes sites under a pilot phase.

Structural cost reduction

Non-IFRS measure. It is calculated as decreases in underlying operating expenditure★ (as defined below) as a result of operational efficiencies, divestments, workforce reductions and other cost saving measures that are expected to be sustainable compared with 2023 levels. The total change between periods in underlying operating expenditure will reflect both structural cost reductions and other changes in spend, including market factors, such as inflation and foreign exchange impacts, as well as changes in activity levels and costs associated with new operations. Estimates of cumulative annual structural cost reduction may be revised depending on whether cost reductions realized in prior periods are determined to be sustainable compared with 2023 levels. Structural cost reductions are stewarded internally to support management's oversight of spending over time.

bp believes this performance measure is useful in demonstrating how management drives cost discipline across the entire organization, simplifying our processes and portfolio and streamlining the way we work. The nearest IFRS measures are production and manufacturing expenses and distributions and administration expenses. A reconciliation of production and manufacturing expenses plus distribution and administration expenses to underlying operating expenditure is provided on page 363.

We are unable to present forward-looking information of the nearest IFRS measures, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to calculate a meaningful comparable IFRS forward-looking financial measure.

Subsidiary

An entity that is controlled by the bp group. Control of an investee exists when an investor is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee.

Surplus cash flow

Surplus cash flow does not represent the residual cash flow available for discretionary expenditures. It is a non-IFRS financial measure that should be considered in addition to, not as a substitute for or superior to, net cash provided by operating activities, reported in accordance with IFRS.

Surplus cash flow refers to the net surplus of sources of cash over uses of cash. Sources of cash include net cash provided by operating activities, cash provided from investing activities and cash receipts relating to transactions involving non-controlling interests. Uses of cash include lease liability payments, payments on perpetual hybrid bonds, dividends paid, cash capital expenditure, the cash cost of share buybacks to offset the dilution from vesting of awards under employee share schemes, cash payments relating to transactions involving non-controlling interests and currency translation differences relating to cash and cash equivalents as presented on the condensed group cash flow statement.

Technical service contract (TSC)

Technical service contract is an arrangement through which an oil and gas company bears the risks and costs of exploration, development and production. In return, the oil and gas company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a profit margin which reflects incremental production added to the oilfield.

Tier 1 and tier 2 process safety events

Tier 1 events are losses of primary containment from a process of greatest consequence – causing harm to a member of the workforce, damage to equipment from a fire or explosion, a community impact or exceeding defined quantities. Tier 2 events are those of lesser consequence. These represent reported incidents occurring within bp's operational HSSE reporting boundary. That boundary includes bp's own operated facilities and certain other locations or situations.

Tight oil and gas

Natural oil and gas reservoirs locked in hard sandstone rocks with low permeability, making the underground formation extremely tight.

Transition growth

Activities, represented by a set of now retired (as of February 2025) transition growth engines, that transition bp toward its objective to be an integrated energy company, and that comprise our low carbon activity★ alongside other businesses that support transition, such as our power trading and marketing business and convenience.

Transition businesses

Business activities (including development, production/manufacture/generation and marketing, distribution and trading) associated with products and services that support energy transition, including in the areas of biogas, biofuels, EV charging, renewable power generation, hydrogen and carbon capture.

Transition growth investment
Capital investment in relation to transition growth★.

UK National Balancing Point
A virtual trading location for sale, purchase and exchange of UK natural gas. It is the pricing and delivery point for the Intercontinental Exchange natural gas futures contract.

Ultra fast / Ultra-fast charging
Electric vehicle charging of greater than or equal to 150kW.

Unconventionals
Resources found in geographic accumulations over a large area, that usually present additional challenges to development such as low permeability or high viscosity. Examples include shale gas and oil, coalbed methane, gas hydrates and natural bitumen deposits. These typically require specialized extraction technology such as hydraulic fracturing or steam injection.

Underlying effective tax rate (ETR)
Non-IFRS measure. The underlying ETR is calculated by dividing taxation on an underlying replacement cost (RC) basis by underlying RC profit or loss before tax. Taxation on an underlying RC basis for the group is calculated as taxation as stated on the group income statement adjusted for taxation on inventory holding gains and losses and adjusting items total taxation. Information on underlying RC profit or loss is provided below. Taxation on an underlying RC basis presented for the operating segments is calculated through an allocation of taxation on an underlying RC basis to each segment. bp believes it is helpful to disclose the underlying ETR because this measure may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. Taxation on an underlying RC basis and underlying ETR are non-IFRS measures. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period.

We are unable to present reconciliations of forward-looking information for underlying ETR to ETR on profit or loss for the period, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include the taxation on inventory holding gains and losses and adjusting items, that are difficult to predict in advance in order to include in an IFRS estimate. A reconciliation to IFRS information is provided on page 360.

Underlying operating expenditure
Non-IFRS measure. A subset of production and manufacturing expenses plus distribution and administration expenses and excludes costs that are classified as adjusting items. It represents the majority of the remaining expenses in these line items but excludes certain costs that are variable, primarily with volumes (such as freight costs). Other variable costs are included in purchases in the income statement. Management believes that underlying operating expenditure is a performance measure that provides investors with useful information regarding the company's financial performance because it considers these expenses to be the principal operating and overhead expenses that are most directly under their control although they also include certain foreign exchange and commodity price effects. The nearest IFRS measures are production and manufacturing expenses and distributions and administration expenses. A reconciliation of production and manufacturing expense plus distribution and administration expenses to underlying operating expenditure is provided on page 363.

Underlying production
Production after adjusting for acquisitions and divestments and entitlement impacts in our production-sharing agreements (PSAs). 2024 underlying production, when compared with 2023, is production after adjusting for acquisitions and divestments, curtailments, and entitlement impacts in our production-sharing agreements/contracts and technical service contract.

Underlying replacement cost (RC) profit or loss / underlying RC profit or loss attributable to bp shareholders
Non-IFRS measure. RC profit or loss★ (as defined above) after excluding net adjusting items and related taxation. See page 313 for additional information on the adjusting items that are used to arrive at underlying RC profit or loss in order to enable a full understanding of the items and their financial impact. Underlying RC profit or loss before interest and tax for the operating segments or customers & products businesses is calculated as RC profit or loss (as defined above) including profit or loss attributable to non-controlling interests before interest and tax for the operating segments and excluding net adjusting items for the respective operating segment or business.

bp believes that underlying RC profit or loss is a useful measure for investors because it is a measure closely tracked by management to evaluate bp's operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period, by adjusting for the effects of these adjusting items. The nearest equivalent measure on an IFRS basis for the group is profit or loss attributable to bp shareholders. The nearest equivalent measure on an IFRS basis for segments and businesses is RC profit or loss before interest and taxation. A reconciliation to IFRS information is provided on page 360 for the group and pages 28-37 for the segments.

Underlying RC profit or loss per share and underlying RC profit or loss per ADS
Non-IFRS measures. Earnings per share is defined in Note 11. Underlying RC profit or loss per ordinary share is calculated using the same denominator as earnings per share as defined in the consolidated financial statements. The numerator used is underlying RC profit or loss attributable to bp shareholders rather than profit or loss attributable to bp shareholders. Underlying RC profit or loss per ADS is calculated as outlined above for underlying RC profit or loss per share except the denominator is adjusted to reflect one ADS equivalent to six ordinary shares. bp believes it is helpful to disclose the underlying RC profit or loss per ordinary share and per ADS because these measures may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is basic earnings per share based on profit or loss for the period attributable to bp shareholders. A reconciliation to IFRS information is provided on page 360.

upstream
upstream includes oil and natural gas field development and production within the gas & low carbon energy and oil production & operations segments. References to upstream exclude Rosneft.

upstream / hydrocarbon plant reliability
bp-operated upstream plant reliability is calculated taking 100% less the ratio of total unplanned plant deferrals divided by installed production capacity, excluding non-operated assets and bpx energy. Unplanned plant deferrals are associated with the topside plant and where applicable the subsea equipment (excluding wells and reservoirs). Unplanned plant deferrals include breakdowns, which does not include Gulf of America weather-related downtime.

upstream unit production costs
upstream unit production costs are calculated as production costs divided by units of production. Production costs do not include ad valorem and severance taxes. Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts disclosed are for bp subsidiaries only and do not include bp's share of equity-accounted entities.

West Texas Intermediate (WTI)
A light sweet crude oil, priced at Cushing, Oklahoma, which serves as a benchmark price for purchases of oil in the US.

Working capital
Movements in inventories and other current and non-current assets and liabilities as stated in the group cash flow statement.

Trade marks
Trade marks of the bp group appear throughout this report. They include:

Amoco, Aral, Aral pulse, BP, bp pulse, Castrol, Castrol ON, Gigahub, PETRO, TA, Thorntons, epic goods and earnify

Trade marks:

REWE to Go – a registered trade mark of REWE.

★ See glossary on **page 351**

Non-IFRS measures reconciliations

Reconciliation of profit or loss for the period to underlying RC profit or loss★

					$ million
	2024	2023	2022	2021	2020
Profit (loss) for the year attributable to bp shareholders	**381**	15,239	(2,487)	7,565	(20,305)
Inventory holding (gains) losses★, before tax	**488**	1,236	(1,351)	(3,655)	2,868
Taxation charge (credit) on inventory holding gains and losses	**(119)**	(292)	332	829	(667)
RC profit (loss)★ for the year	**750**	16,183	(3,506)	4,739	(18,104)
Net (favourable) adverse impact of adjusting items★, before tax	**9,344**	(1,143)	29,781	8,697	16,649
Adjusting items total taxation	**(1,179)**	(1,204)	1,378	(621)	(4,235)
Underlying RC profit or loss for the year	**8,915**	13,836	27,653	12,815	(5,690)

Reconciliation of basic earnings per ordinary share to underlying RC profit per ordinary share★

			Per ordinary share – cents
	2024	2023	2022
Profit (loss) for the year attributable to bp shareholders	**2.38**	87.78	(13.10)
Inventory holding (gains) losses, before tax	**2.98**	7.12	(7.12)
Taxation charge (credit) on inventory holding gains and losses	**(0.73)**	(1.69)	1.75
	4.63	93.21	(18.47)
Net (favourable) adverse impact of adjusting items, before tax	**56.95**	(6.58)	156.84
Taxation charge (credit) on adjusting items	**(7.18)**	(6.94)	7.26
Underlying RC profit for the year	**54.40**	79.69	145.63

Reconciliation of basic earnings per ADS to underlying RC profit per ADS★

			Per ADS – dollars
	2024	2023	2022
Profit (loss) for the year attributable to bp shareholders	**0.14**	5.27	(0.79)
Inventory holding (gains) losses, before tax	**0.18**	0.43	(0.43)
Taxation charge (credit) on inventory holding gains and losses	**(0.04)**	(0.11)	0.11
	0.28	5.59	(1.11)
Net (favourable) adverse impact of adjusting items, before tax	**3.42**	(0.40)	9.41
Taxation charge (credit) on adjusting items	**(0.44)**	(0.41)	0.44
Underlying RC profit for the year	**3.26**	4.78	8.74

Reconciliation of effective tax rate (ETR) to ETR on RC profit or loss and underlying ETR★

Taxation (charge) credit

			$ million
	2024	2023	2022
Taxation on profit or loss before taxation for the year	**(5,553)**	(7,869)	(16,762)
Adjusted for taxation on inventory holding gains and losses	**119**	292	(332)
Taxation on a RC profit or loss basis	**(5,672)**	(8,161)	(16,430)
Adjusted for adjusting items total taxation	**1,179**	1,204	(1,378)
Taxation on an underlying RC basis	**(6,851)**	(9,365)	(15,052)

Effective tax rate

			%
	2024	2023	2022
ETR on profit or loss before taxation for the year	**82**	33	109
Adjusted for inventory holding gains and losses	**(4)**	–	8
ETR on RC profit or loss	**78**	33	117
Adjusted for adjusting items total taxation	**(37)**	6	(83)
Underlying ETR	**41**	39	34

Return on average capital employed (ROACE)★

	2024	2023	2022	2021	2020
					$ million
Profit (loss) for the year attributable to bp shareholders	**381**	15,239	(2,487)	7,565	(20,305)
Inventory holding (gains) losses, before tax	**488**	1,236	(1,351)	(3,655)	2,868
Taxation charge (credit) on inventory holding gains and losses	**(119)**	(292)	332	829	(667)
Adjusting items, before tax	**9,344**	(1,143)	29,781	8,697	16,649
Taxation charge (credit) on adjusting items	**(1,179)**	(1,204)	1,378	(621)	(4,235)
Underlying RC profit	**8,915**	13,836	27,653	12,815	(5,690)
Interest expense[a]	**3,113**	2,569	1,632	1,322	1,808
Taxation on interest expense	**(404)**	(661)	(296)	(195)	(406)
Non-controlling interests (NCI)	**848**	641	1,130	922	(424)
	12,472	16,385	30,119	14,864	(4,712)
Total equity	**78,318**	85,493	82,990	90,439	85,568
Finance debt	**59,547**	51,954	46,944	61,176	72,664
Capital employed	**137,865**	137,447	129,934	151,615	158,232
Less: Goodwill	**14,888**	12,472	11,960	12,373	12,480
Cash and cash equivalents	**39,204**	33,030	29,195	30,681	31,111
	83,773	91,945	88,779	108,561	114,641
Average capital employed excluding goodwill and cash and cash equivalents	**87,859**	90,362	98,670	111,601	124,367
Profit (loss) for the year attributable to bp shareholders divided by total equity	**0.5%**	17.8%	(3.0)%	8.4%	(23.7)%
ROACE	**14.2%**	18.1%	30.5%	13.3%	(3.8)%

a Finance costs, as reported in the Group income statement, were $4,683 million (2023 $3,840 million, 2022 $2,703 million, 2021 $2,857 million, 2020 $3,115 million). Interest expense is finance costs excluding lease interest of $441 million (2023 $346 million, 2022 $257 million, 2021 $306 million, 2020 $350 million), unwinding of discount on provisions and other payables of $1,013 million (2023 $912 million, 2022 $808 million, 2021 $890 million, 2020 $957 million) and other adjusting items related to finance costs of $116 million (2023 $13 million, 2022 $6 million, 2021 $339 million).

Adjusted EBIDA★

	2024	2023	2022
			$ million
Profit (loss) for the period	**1,229**	15,880	(1,357)
Finance costs	**4,683**	3,840	2,703
Net finance (income) expense relating to pensions and other post-employment benefits	**(168)**	(241)	(69)
Taxation	**5,553**	7,869	16,762
Profit before interest and tax	**11,297**	27,348	18,039
Inventory holding (gains) losses, before tax	**488**	1,236	(1,351)
	11,785	28,584	16,688
Net (favourable) adverse impact of adjusting items, before interest and tax	**8,839**	(1,548)	29,356
	20,624	27,036	46,044
Taxation on an underlying RC basis[a]	**(6,851)**	(9,365)	(15,052)
	13,773	17,671	30,992
Add back: Depreciation, depletion and amortization	**16,622**	15,928	14,318
Exploration expenditure written off	**766**	746	385
Adjusted EBIDA	**31,161**	34,345	45,695

a A definition for taxation on an underlying RC basis is included under Underlying ETR in the glossary on page 359.

★ See glossary on **page 351**

Adjusted EBITDA★

			$ million
	2024	2023	2022
Profit (loss) for the period	**1,229**	15,880	(1,357)
Finance costs	**4,683**	3,840	2,703
Net finance (income) expense relating to pensions and other post-employment benefits	**(168)**	(241)	(69)
Taxation	**5,553**	7,869	16,762
Profit before interest and tax	**11,297**	27,348	18,039
Inventory holding (gains) losses, before tax	**488**	1,236	(1,351)
	11,785	28,584	16,688
Net (favourable) adverse impact of adjusting items, before interest and tax	**8,839**	(1,548)	29,356
	20,624	27,036	46,044
Add back: Depreciation, depletion and amortization	**16,622**	15,928	14,318
Exploration expenditure written off	**766**	746	385
Adjusted EBITDA	**38,012**	43,710	60,747

Reconciliation of RC profit before interest and tax for gas & low carbon energy and oil production & operations to adjusted EBITDA

			$ million
	2024	2023	2022
gas & low carbon energy			
RC profit before interest and tax	**3,569**	14,080	14,696
Less: Net favourable (adverse) impact of adjusting items	**(3,234)**	5,358	(1,367)
Underlying RC profit before interest and tax	**6,803**	8,722	16,063
Add back: Depreciation, depletion and amortization	**4,835**	5,680	5,008
Exploration expenditure written off	**222**	362	2
Adjusted EBITDA	**11,860**	14,764	21,073
oil production & operations			
RC profit before interest and tax	**10,789**	11,191	19,721
Less: Net favourable (adverse) impact of adjusting items	**(1,148)**	(1,590)	(503)
Underlying RC profit before interest and tax	**11,937**	12,781	20,224
Add back: Depreciation, depletion and amortization	**6,797**	5,692	5,564
Exploration expenditure written off	**544**	384	383
Adjusted EBITDA	**19,278**	18,857	26,171

Underlying operating expenditure★reconciliation

		$ million
	2024	2023
From group income statement		
Production and manufacturing expenses	**26,584**	25,044
Distribution and administration expenses	**16,417**	16,772
	43,001	41,816
Less certain variable costs:		
Transportation and shipping costs	**11,531**	10,752
Environmental costs	**2,972**	3,169
Marketing and distribution costs	**1,882**	2,430
Commission, storage and handling costs	**1,519**	1,633
Other variable costs and non-cash costs	**1,495**	743
Certain variable costs	**19,399**	18,727
Operating expenditure★	**23,602**	23,089
Less certain adjusting items★:		
Gulf of America oil spill	**51**	57
Environmental and related provisions	**181**	647
Restructuring, integration and rationalization costs	**222**	(37)
Fair value accounting effects – derivative instruments relating to the hybrid bonds	**221**	(630)
Other certain adjusting items	**601**	419
Certain adjusting items	**1,276**	456
Underlying operating expenditure	**22,326**	22,633
Underlying operating expenditure reduction relative to 2023	**(307)**	
Increase/(decrease) in underlying operating expenditure due to inflation, exchange, portfolio changes and organic growth	**443**	
Structural cost reduction★	**(750)**	

The Directors' report on pages 69-87, 88 (in respect of the remuneration committee), 111-113, 223-250 and 311-363 was approved by the board and signed on its behalf by Ben J. S. Mathews, company secretary on 6 March 2025.

BP p.l.c.
Registered in England and Wales No. 102498

★ See glossary on **page 351**

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)

/s/ Ben J. S. Mathews
Company secretary
6 March 2025

Cross reference to Form 20-F

Information about this report

This document constitutes the Annual Report and Accounts in accordance with UK requirements and the Annual Report on Form 20-F in accordance with the US Securities Exchange Act of 1934, for BP p.l.c. for the year ended 31 December 2024. A cross reference to Form 20-F requirements is included on page 365.

This document contains the Strategic report on the inside front cover and pages 1-68 and the Directors' report on pages 69-87, 88 (in part only), 111-113, 223-250 and 311-363. The Strategic report and the Directors' report together include the management report required by DTR 4.1 of the UK Financial Conduct Authority's Disclosure Guidance and Transparency Rules. The Directors' remuneration report is on pages 88-110. The consolidated financial statements of the group are on pages 115-222 and the corresponding reports of the auditor are on pages 116-139. The parent company financial statements of BP p.l.c. are on pages 251-310.

The Directors' statements (comprising the Statement of directors' responsibilities; Risk management and internal control; Longer-term viability; Going concern; and Fair, balanced and understandable), the independent auditor's report on the annual report and accounts to the members of BP p.l.c., the parent company financial statements of BP p.l.c. and corresponding auditor's report do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

bp Annual Report and Form 20-F 2024 may be downloaded from bp.com/annualreport. No material on the bp website, other than the items identified as *bp Annual Report and Form 20-F 2024*, forms any part of this document. References in this document to other documents on the bp website, such as *bp Energy Outlook 2024*, and *bp Sustainability Report* are included as an aid to their location and are not incorporated by reference into this document.

BP p.l.c. is the parent company of the bp group of companies. The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001. Where we refer to the company, we mean BP p.l.c. The company and each of its subsidiaries★ are separate legal entities. Unless otherwise stated or the context otherwise requires, the term "BP" or "bp" and terms such as "we", "us" and "our" are used in this report for convenience to refer to one or more of the members of the bp group instead of identifying a particular entity or entities. Information in this document reflects 100% of the assets and operations of the company and its subsidiaries that were consolidated at the date or for the periods indicated, including non-controlling interests.

The company's primary share listing is the London Stock Exchange. In the US, the company's securities are traded on the New York Stock Exchange (NYSE) in the form of ADSs (see page 342 for more details) and in Germany in the form of a global depositary certificate representing bp ordinary shares traded on the Frankfurt Stock Exchange. The company delisted from the Hamburg and Düsseldorf Stock Exchanges on 20 December 2024 and announced its intention to delist from the Frankfurt Stock Exchange on 18 April 2024.

The term 'shareholder' in this report means, unless the context otherwise requires, investors in the equity capital of BP p.l.c., both direct and indirect. As the company's shares, in the form of ADSs, are listed on the NYSE, an Annual Report on Form 20-F is filed with the SEC. Ordinary shares are ordinary fully paid shares in BP p.l.c. of 25 cents each. Preference shares are cumulative first preference shares and cumulative second preference shares in BP p.l.c. of £1 each.

Registered office and our worldwide headquarters:
BP p.l.c.

1 St James's Square
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UK

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Our agent in the US:

BP America Inc.

501 Westlake Park Boulevard
Houston, Texas 77079
US

Tel +1 281 366 2000

Registered in England and Wales No. 102498.
London Stock Exchange symbol 'BP.'

Exhibits

The following documents are filed in the Securities and Exchange Commission (SEC) EDGAR system, as part of this Annual Report on Form 20-F, and can be viewed on the SEC's website.

Exhibit 1	Memorandum and Articles of Association of BP p.l.c.†
Exhibit 2	Description of rights of each class of securities registered under Section 12 of the Securities Exchange Act of 1934†
Exhibit 4.1	The BP Executive Directors' Incentive Plan†
Exhibit 4.4	Director's Service Agreement for K Thomson***†
Exhibit 4.7	Director's Service Agreement for M Auchincloss***†
Exhibit 4.10	The BP Share Award Plan 2015**†
Exhibit 8	Subsidiaries (included as Note 37 to the Financial Statements)
Exhibit 11.1	Code of Ethics*†
Exhibit 11.2	Insider trading policy and procedure
Exhibit 12	Rule 13a – 14(a) Certifications†
Exhibit 13	Rule 13a – 14(b) Certifications#†
Exhibit 15.1	Consent of Netherland, Sewell & Associates†
Exhibit 15.2	Report of Netherland, Sewell & Associates†
Exhibit 15.3	Consent Decree**†
Exhibit 15.4	Gulf states Settlement Agreement**†
Exhibit 15.5	Consent of Deloitte LLP†
Exhibit 17	Guaranteed Securities†
Exhibit 97	Executive Compensation Clawback Policy†
Exhibit 101	Inline XBRL data files
Exhibit 104	Cover page interactive data file (formatted as Inline XBRL and contained in Exhibit 101)

* Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2009.

** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2015.

*** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2023.

\# Furnished only.

† Included only in the annual report filed in the Securities and Exchange Commission EDGAR system.

The total amount of long-term securities of BP p.l.c. and its subsidiaries under any one instrument does not exceed 10% of their total assets on a consolidated basis.

The company agrees to furnish copies of any or all such instruments to the SEC on request.

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bp's corporate reporting suite includes information about our financial and operating performance, sustainability performance and global energy trends and projections.

bp.com

bp Annual Report and Form 20-F 2024
Details of our financial and operating performance in print and online.

bp.com/annualreport

bp Sustainability Report 2024
Details of our sustainability performance with additional information online.

bp.com/sustainability

bp Energy Outlook 2024
Provides our projections of future energy trends and factors that could affect them out to 2040.

bp.com/energyoutlook

Group databook 2020-2024
Five-year financial and operating data in PDF and Excel format.

bp.com/financial-disclosure

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